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BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

BOB BURNS – Chairman
BOYD DUNN
SANDRA KENNEDY
JUSTIN OLSON
LEA MÁRQUEZ PETERSON

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN.	Docket No. E-01345A-19-0236 **NOTICE OF FILING SIERRA CLUB'S DIRECT TESTIMONY**

Pursuant to the Procedural Order issued by the Arizona Corporation Commission on July 31, 2020, Sierra Club hereby files the Direct Testimony of Cheryl Roberto and Tyler Comings, to be presented at the December 14, 2020 Hearing in this matter.

Confidential and highly confidential versions of Tyler Comings' Direct Testimony are being provided under seal to the Legal Division for distribution to the Commission and to Arizona Public Service for distribution to parties with whom it has entered into a Protective Agreement

RESPECTFULLY SUBMITTED this 2nd day of October, 2020.

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IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN.	Docket No. E-01345A-19-0236

Direct Testimony of
Cheryl Roberto

On Behalf of
Sierra Club

On the Topics of:

Default Bill Simplification

Formula Rate Concept Alternative

Ratepayer-Backed Securitization

October 2, 2020

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LIST OF ATTACHMENTS

Attachment CR-1:	Resume of Cheryl Roberto
Attachment CR-2:	Rachel Gold et al., *Leveraging Advanced Metering Infrastructure to Save Energy* (ACEEE Revised Jan. 27, 2020), *available at* https://www.aceee.org/sites/default/files/pdfs/u2001.pdf.
Attachment CR-3:	Public Discovery Responses
Attachment CR-4:	Melissa Whited & Cheryl Roberto, *Multi-Year Rate Plans: Core Elements and Case Studies* (Prepared for Maryland PC51 and Case 9618 Sept. 30, 2019), *available at* https://www.synapse-energy.com/sites/default/files/Synapse-Whitepaper-on-MRPs-and-FRPs.pdf.
Attachment CR-5:	Ron Lehr & Sonia Aggarwal, *Utility Models: Questions for Regulators and Stakeholders to Ask and Answer as Utilities Evolve* (Energy Innovation Feb. 2017), *available at* https://energyinnovation.org/wp-content/uploads/2017/02/UtilityRegModels_QuestionsList.pdf.

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, title, and employer.

A. My name is Cheryl Roberto. I am employed by Synapse Energy Economics, Inc. as a Senior Principal. My business address is 485 Massachusetts Avenue, Cambridge, MA 02139.

Q. Please describe Synapse Energy Economics.

A. Synapse Energy Economics is a research and consulting firm specializing in electricity industry regulation, planning, and analysis. Synapse works for a variety of clients, with an emphasis on consumer advocates, regulatory commissions, and environmental advocates.

Q. Please summarize your professional and educational experience.

A. For more than 30 years I have managed, regulated, or guided the operation of utilities and regulatory policy related to public utilities. From 2008 until 2012, I served as a Commissioner of the Public Utilities Commission of Ohio ("PUCO"), where I initiated a national pilot partnership with the U.S. Department of Energy to support cost-effective deployment of combined heat and power systems. I served as Co-Chair of the 2012 National Electricity Forum. As a member of the National Association of Regulatory Utility Commissioners ("NARUC"), I served on the Task Force on Environmental Regulation and Generation, the Committee on Electricity, and Vice Chair of the Committee on Critical Infrastructure. Immediately after my service as a Commissioner, I led a nation-wide program advocating for regulatory reform as Associate Vice President of the

Environmental Defense Fund's Clean Energy Program. The goal of the program was accelerating the adoption of renewable energy technologies; modernizing U.S. energy infrastructure; and eliminating financial and regulatory barriers that prevent widespread implementation of renewables, energy efficiency, and innovative energy generation and distribution approaches. Prior to my service as a Commissioner, I led the Department of Public Utilities for the City of Columbus as its Director, serving, with a staff of 1,300, the 1.1 million residents of the Central Ohio region. From 1987 through 2000, I practiced law as an Assistant Attorney General in Ohio, Assistant Counsel in Pennsylvania, and Assistant City Attorney in Columbus, Ohio. I hold a B.A. in Political Science from Kent State University, and a J.D. from the Moritz College of Law at The Ohio State University. My resume is attached hereto as Attachment CR-1.

Q. On whose behalf are you testifying in this case?

A. I am appearing on behalf of the Sierra Club.

Q. Have you testified previously before the Arizona Corporation Commission?

A. No, I have not.

Q. Have you testified previously before any other tribunals?

A. Yes. I have previously appeared before the Federal Energy Regulatory Commission ("FERC") and the U.S. Senate Energy and Natural Resources Committee. I have also provided testimony before the Public Utilities

Commission of Ohio, the Indiana Utility Regulatory Commission, and the Colorado Public Utilities Commission.

Q. What is the purpose of your testimony?

A. I have been retained by the Sierra Club to review the Arizona Public Service ("APS") application pertaining to its default simplified bill request and its formula rate concept alternative. I am also evaluating whether the APS application would be improved if APS were to seek ratepayer-backed securitization as an alternative to APS's extended cost recovery proposals or a potential earlier retirement of Four Corners Units 4 and 5.

Q. What materials did you rely on to develop your testimony?

A. The sources for my testimony and exhibits are public documents, industry literature, and responses to discovery requests, as well as my personal knowledge and experience.

Q. Did you prepare or direct the preparation of this testimony?

A. Yes.

Q. How is your testimony organized?

A. I have organized my testimony as follows:

I. Introduction and Qualifications

II. Summary of Conclusions and Recommendations

III. Default Bill Simplification

IV. APS Formula Rate Concept Alternative

V. Securitization

II. SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

APS Default Bill Simplification

Q. Please summarize your primary conclusions regarding the APS proposal for Default Bill Simplification.

A. My primary conclusions regarding the APS proposal for Default Bill Simplification are as follows:

- APS's proposal for default bill simplification amounts to a request for a permanent waiver of A.C.C. R14-2-210, adopted to protect consumers. The rule, as adopted, ensures customers receive important information about their utility bill. Because APS is also proposing to default every customer into a simplified bill, it is effectively seeking a permanent rule waiver applicable to every customer. A waiver of this broad and permanent nature is functionally a rule amendment. As an administrative process matter, is not appropriate to amend a rule via a waiver. From a substantive perspective, it is difficult to justify providing customers with less information, particularly given the deficiencies in APS's current Customer Outreach and Education Program efforts and the recommendations of the Alexander Report that was commissioned to investigate those shortcomings.
- APS customer access to energy data is inadequate, as APS fails to provide customers the ability to access and share their data consistent with the Green Button Connect My Data standards described below in Section III. Specifically, customers are required to share personal account information when they wish to share energy usage data with third parties. They receive data in a format that is difficult to use. They do not have a seamless and secure method to authorize the transmittal of their energy usage data, and only their

energy usage data, to third parties. Further, APS does not provide energy data in 15-minute intervals. It is critical that customers receive the energy data in a form that allows them to make informed decisions and to share that data while protecting their privacy. The data's value is realized primarily when utilities, technology companies, and service providers process, analyze, and perhaps even act upon the energy data on behalf of the customer. It is APS's responsibility to do this well, but customers should also be able to seek guidance outside of the utility from third party providers.

Q. Please summarize your primary recommendations regarding the APS proposal for Default Bill Simplification.

A. My primary recommendations regarding the APS proposal for Default Bill Simplification are as follows:

- The Commission should reject the APS proposal for default bill simplification. APS has not presented sufficient evidence to support what would function as a permanent waiver of the consumer information protections of A.C.C. R14-2-210. When or if customers have access to their energy data in a form that complies with Green Button Connect My Data, it may be appropriate to consider a rule amendment.
- APS customers have paid for the Advanced Metering Infrastructure ("AMI"). They should receive value from it. The Commission should direct APS to implement Green Button Connect My Data as soon as practicable.
- The Commission should direct APS to comply with the U.S. Department of Energy's *Data Privacy and the Smart Grid: A Voluntary Code of Conduct*.
- The Commission should direct APS to investigate and report on whether the investment required to provide more granular data in the form of one-, five-, or 15-minute intervals to customers would be cost-effective.

- The Commission should direct APS to track and report quarterly metrics that will inform the Commission, APS, and customers on APS's progress toward leveraging the benefits of AMI for its customers. These should include:
    - Customer usage of energy portal - one-time or regular access.
    - Total number and percentage of customers opting out of or taking a tariff.
    - Number of third parties that successfully access customer data through Green Button Connect My Data or other utility data-sharing method; percentage of customers able to authorize third-party service company requests on first attempt (target: 95%); percentage of time third-party service provider receives access when authorized by customers (target: 95%).
    - Customer-initiated changes to their rate plans.
    - APS-initiated changes to customer rate plans.
    - Number of customers not on the "best" or "most economical rate" by rate class.
    - Frequency and type of complaints.
    - Call Center performance.
    - Results of customer research on messaging and bill presentment.
    - Enrollment for limited-income programs.
    - Achievement of participation objectives for demand-side management programs.
    - Analysis of the impact of rate design on system benefits, such as peak load reduction and lower generation supply costs.
    - Key indicia of credit and collection activities, such as disconnection notices, disconnections, and payment arrangements.

APS Formula Rate Concept Alternative

Q. Please summarize your primary conclusions regarding the APS Formula Rate Concept Alternative.

A. My primary conclusions regarding the APS Formula Rate Concept Alternative are as follows:

- The APS Formula Rate Concept Alternative does not improve upon status quo regulation. The Formula Rate Concept Alternative does nothing to address challenges due to changes underway in the electric industry related to fuel for centralized generation and the introduction of cost-effective distributed energy resources. It would not provide additional tools to address public policy goals around decarbonization and makes no meaningful contribution to performance. Most significantly, it would reduce cost-containment features that exist under current cost-of-service regulation in Arizona.
- Alternative regulation could ensure that electric utilities navigate the changes underway in the electricity industry while continuing to provide cost-effective universal service. To achieve this, utilities must successfully harness and optimize all available technologies. Utilities will own some of these technologies, but other technologies will be owned by their customers or third parties. Both status quo regulation and the APS Formula Rate Concept Alternative, if adopted, would require APS to act against its financial interest when supporting clean, efficient, distributed resources. Alternative forms of regulation could help a utility thrive within the transition underway, contain costs, help to achieve public policy goals such as decarbonization, and improve utility performance.
- Performance-based regulation in the form of multi-year rate plans in combination with performance incentive mechanisms ("PIM"), which include well-crafted metrics, scorecards, and financial incentive mechanisms, is an alternative form of regulation that can be a powerful driver toward cost-effective, decarbonized energy systems.

- PIMs can be used to express regulatory expectations and connect those expectations with financial consequences inside a multi-year rate plan or as part of traditional cost-of-service regulation.
- The design and implementation of an effective multi-year rate plan deserves a robust stakeholder process as part of the Commission's forthcoming investigation into performance-based regulation.
- PIMs have long been incorporated into both multi-year rate plans and into cost-of-service-based regulation. PIMs offer the advantage of being able to be implemented incrementally and iteratively. It is appropriate to consider PIMs once the Commission identifies a regulatory policy goal and desired performance objectives or outcomes. It would be appropriate for the Commission to direct APS to begin tracking metrics now. This data collected will inform the investigation regarding PIMs.

Q. Please summarize your primary recommendations regarding APS Formula Rate Concept Alternative.

A. My primary recommendations regarding the APS Formula Rate Concept Alternative are as follows:

- The Commission should reject the APS Formula Rate Concept Alternative.
- More broadly, the Commission should not pursue any formula rate structure.
- The Commission should consider adopting performance-based regulation, in a separate docket that investigates comprehensive performance-based regulation and includes a robust stakeholder process. This could be an expansion of the previously opened Docket No. E-00000A-20-0019 to investigate PIMs.[1]

[1] *In the Matter of the Investigation of the Arizona Corporation Commission into the Role of Performance Incentive Mechanisms in Regulated Investor Owned Electric Utility Rate Cases in Arizona*, Docket No. E-00000A-20-0019 (Ariz Corp. Comm'n Feb. 6, 2020).

- The Commission should direct APS to begin tracking at least the metrics outlined in my recommendations regarding Default Bill Simplification beginning on page 28.

Ratepayer-Backed Securitization

Q. Please summarize your primary conclusions regarding Ratepayer-Backed Securitization.

A. My primary conclusions regarding Ratepayer-Backed Securitization are as follows:

- A rate case is an opportune moment to evaluate whether portions of the utility's capital need could be more cost-effectively managed through ratepayer-backed bonds. In this matter, I see at least three opportunities to consider ratepayer-backed bonds as a tool to improve customer outcomes.

- APS has suggested extending the cost recovery time for deferred expenses related to the Four Corners SCRs and the Ocotillo Modernization Project amortization schedules in order to mitigate bill impacts to customers.[2] The deferral at December 31, 2020 for the Ocotillo Modernization Project is $62 million.[3] The SCR deferral is $33.2 million.[4] APS also proposes to extend recovery time for the Cholla Unit 2 regulatory asset amortization.[5] If the Commission agrees that APS should recover these deferrals, then instead of extending the cost recovery—which lowers customers impacts in the near term but increases overall costs—the Commission could consider whether these should be funded by ratepayer-backed securities which could lower customers' overall costs and similarly mitigate rate impacts.

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[2] Ariz. Pub. Serv. Application at 18, Docket No. E-01345A-19-0236 (Oct. 31, 2019), *available at* https://docket.images.azcc.gov/E000003517.pdf.
[3] Direct Testimony of Elizabeth A. Blankenship at 35:1-4 [hereinafter "Blankenship Direct"].
[4] *Id.* at 36:19-20.
[5] *Id.* at 41:4-9.

- Additionally, concurrent with my testimony, Tyler Comings filed testimony on behalf of the Sierra Club finding that APS would enjoy substantial savings if it were to retire Four Corners Units 4 and 5 as quickly as possible instead of in 2031. Securitization may be a useful tool in implementing an earlier-than-anticipated retirement of Four Corners Units 4 and 5. This use is also consistent with the additional analyses requested by Chairman Burns in this proceeding[6] and the suggestion made by Chairman Burns within the Energy Rules docket.[7]

- The Commission could conservatively expect that ratepayer-backed bonds could reduce the cost of capital by over half, offering customers a substantial savings opportunity.

- A commission adopting a finance order to authorize securitization could consider the following design features to ensure that the transaction achieves the intended benefits:

    - The Commission retains authority to approve the investment banking firm managing the offering.

    - The Commission retains an independent advisor to oversee the transaction and to advise the Commission.

    - Proceeds of the ratepayer-backed bonds may be used only to replace existing capital (including the cost of the bonds), not to undertake new debt.

    - Savings from securitization should be passed along to customers directly or indirectly as a public benefit through funding of costs required to assure a just transition during the early retirement of an asset, including but not limited to severance pay and job training expenses for affected employees.

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[6] Letter from Chairman Burns, Docket No. E-01345A-19-0236 (Aug. 11, 2020), *available at* https://docket.images.azcc.gov/E000008353.pdf; Letter from Chairman Burns, Docket No. E-01345A-19-0236 (Sept. 1, 2020), *available at* https://docket.images.azcc.gov/E000008707.pdf.

[7] Letter from Chairman Burns at 2, Docket No. RU-00000A-18-0284 (Ariz. Corp. Comm'n Mar. 25, 2020), *available at* https://docket.images.azcc.gov/E000005560.pdf [hereinafter "Mar. 25, 2020 Letter from Chairman Burns"].

- Bonds must be competitively marketed as opposed to sold through private negotiation.
- Financing costs and weighted average interest of the bonds are capped at levels to assure the expected benefits.
- The Commission retains authority to approve the bond structuring and pricing.

Q. Please summarize your primary recommendations regarding Ratepayer-Backed Securitization.

A. My primary recommendations regarding ratepayer-backed securitization are as follows:

- The Commission should consider retaining a qualified expert to conduct an independent evaluation to determine whether there are large, well-defined, non-recurring expenses on the utility's balance sheet that could cost-effectively be funded by ratepayer-backed bonds.
- The Commission should consider the tool of securitization when evaluating the opportunities to close fossil fuel generation units that have become or soon will be non-economic.

III. DEFAULT BILL SIMPLIFICATION

APS Proposal for Default Bill Simplification

Q. What has APS proposed regarding Bill Simplification?

A. APS proposes to begin issuing bills that include only a customer's current service plan, total kWh usage with a split of on- and off-peak, as well as usage history, and an account summary including the amount owed during the current month.[8]

Q. What explanation has APS provided for its motivation in proposing "bill simplification"?

A. Ms. Lockwood testified that APS has "heard from customers the desire to have a simplified and easier to understand bill."[9]

Q. Did APS undertake a stakeholder consultation process to conclude that its customers wanted a simplified bill?

A. Not that I have seen. If APS conducted stakeholder consultation before arriving at this conclusion, Ms. Lockwood did not describe it or explain how it was considered in developing the proposed bill redesign. However, Barbara R. Alexander, the independent consultant retained by Staff to review APS Customer Outreach and Education Plan, noted in her report (hereinafter "Alexander Report") that:

> APS is also currently undergoing a process to change the design and presentation of material information on its customer bills. APS has consulted with stakeholders on its bill design options, and, unlike its development of messaging and communications in 2017, customer focus groups were convened to gather additional input. According to

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[8] Direct Testimony of Barbara Lockwood at 12:25-13:6 [hereinafter "Lockwood Direct"].
[9] *Id.* at 13:8-9.

> APS, its new bill design is not finalized but will be implemented as part of the resolution of this pending rate case. … While APS's approach to include customer and stakeholder input is a positive step, the lack of any process for Commission review and input for this bill redesign should be remedied.[10]

Q. What is the Alexander Report?

A. This rate case was precipitated by a Commission order finding, among other matters, that APS's Customer Outreach and Education Program ("COEP") was so ineffective as to require Staff to select and hire an independent consultant, paid for by APS, to develop a program to properly and adequately educate customers on all aspects of APS's rate plans.[11] Barbara R. Alexander, the independent consultant retained by Staff to review the APS COEP prepared a report describing the numerous deficiencies she found.[12] This is the report that I reference as the Alexander Report. In that report, she recommended that the Commission order APS to create and propose a comprehensive COEP that, as a "key requirement," should include performance standards and reporting mechanisms that would allow a meaningful and regular review of APS's progress.[13]

Q. Did the Alexander Report include any recommendations regarding bill design?

A. Yes. The report recommended that:

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[10] Barbara R. Alexander, Barbara Alexander Consulting LLC, *An Evaluation of Arizona Public Service Company's Customer Education Plan and Its Implementation* 35 (May 19, 2020), *available at* https://docket.images.azcc.gov/E000006583.pdf [hereinafter "Alexander Report"].

[11] Order No. 77270 at 8:12-15, Docket No. E-0134A-19-0003 (Ariz. Corp. Comm'n June 27, 2019), *available at* https://docket.images.azcc.gov/0000198805.pdf.

[12] Alexander Report.

[13] *Id.* at 36.

One aspect of the bill redesign that should be the focus of consumer and Commission attention is the presentation of demand charges, how they are calculated and what specific usage profile triggered the billed demand charge.

Q. If the APS proposal is adopted, how would a customer's bill change?

A. Referencing the sample bill provided on APS's website, it appears that the simplified bill would no longer provide information regarding the customer account charge, delivery service charge, demand charge, environmental benefits surcharge, federal environmental improvement surcharge, system benefits charges, power supply adjustment, metering charge, meter reading charge, billing charge, demand charge on-peak, federal transmission and ancillary services, federal transmission cost adjustment, Lost Fixed Cost Recovery (LFCR) adjustor, and the Tax Expense Adjustor Mechanism.[14]

Q. Under APS's proposal, which customers would receive a simplified bill?

A. All customers would receive a "simplified bill." APS suggests that customers could, on their own initiative, opt out of a simplified bill to continue receiving their current complete bill.[15] APS does not provide a description of the effort required by a customer to continue receiving a customary bill.

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[14] See the sample bill information provided by APS: Ariz. Pub. Serv., *Example Bill – Saver Choice Plus*, https://www.aps.com/en/Residential/Billing-and-Payment/Understanding-Your-Bill/Sample-Bill (last visited July 30, 2020).

[15] *Id.*

Q. Does this proposal require any rule waivers?

A. Yes. APS has requested that the Commission waive the requirements of A.A.C. R14-2-210.[16]

Q. When is it appropriate to waive a rule?

A. From my experience as a Commissioner in Ohio, I find it appropriate to waive an administrative rule during emergencies when the rule impeded an emergency response. It can also be useful to authorize a limited waiver of a rule when the rule impedes the successful operation of a pilot program.

Q. Do the circumstances presented by APS suggest that a rule waiver is appropriate?

A. No. APS seems to be requesting a permanent waiver of a rule adopted to protect consumers. The rule, as adopted, ensures customers receive important information about their utility bills. Because APS is also proposing to default every customer into a simplified bill, it is effectively seeking a permanent rule waiver applicable to every customer. A waiver of this broad and permanent nature is functionally a rule amendment. As an administrative procedural matter, it is not appropriate to amend a rule via a waiver.[17] From a substantive perspective, it is difficult to justify providing customers with less information, particularly given the deficiencies in APS's current Customer Outreach and Education Program efforts, the recommendations of the Alexander Report commissioned to investigate those

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[16] Lockwood Direct at 13:16-18.
[17] Ariz. Rev. Stat. § 41-1030(A).

shortcomings, and the current inadequate access to energy data APS provides (described below).

The Importance of Easy Access to Comprehensive Energy Data

Q. What is customer "energy data"?

A. A customer's energy data informs a customer how much energy they are using, when, and at what price. It reflects their measured energy consumption and related pricing information.

Q. How is customer energy data generated?

A. A customer's meter provides measured energy consumption. According to the Energy Information Agency, an AMI metering system measures and records electricity usage at a minimum of hourly intervals and provides that data to both the utility and the customer at least once a day. AMI meters range from basic hourly interval meters to real-time meters with built-in two-way communication capable of recording and transmitting instantaneous data.[18]

Q. Why would a customer access their energy data?

A. Customers who understand when they use energy and how much it costs at that time are able to: assess and choose the utility tariff most beneficial to them; determine whether and which energy efficiency or demand-side management measures would be cost-effective investments; determine whether battery storage

[18] U.S. Energy Info. Admin., *Frequently Asked Questions (FAQS)*: *How many smart meters are installed in the United States, and who has them?*, https://www.eia.gov/tools/faqs/faq.php?id=108&t=3 (last visited July 30, 2020).

or a solar installation or other distributed energy resource would be worthwhile; and make decisions about when or how to charge an electric vehicle.

Q. How would a customer use their energy data to save energy?

A. Simple timely feedback can help customers save energy. Research has documented that customers with near real-time and behavioral feedback enjoy energy saving from 1 to 8 percent.[19] Customers save even more when energy data is paired with customer engagement to guide them to energy efficiency programs or measures most suited for their energy profile or to use energy when it is most cost-effective for them. A dozen studies found customers saved from 6 percent to 18 percent of energy when they had access to meter data coupled with actionable feedback and smart controls.[20]

Q. With whom might a customer want to share their energy data?

A. Energy data may provide little useful information to a customer on its own. The value of the data will likely come from the activities of utilities, technology companies, and service providers who process, analyze, and perhaps even act upon the energy data on behalf of the customer. A customer may wish to share their energy data with third-party providers of energy efficiency products and services, other distributed energy resource providers, or energy consultants who

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[19] Attachment CR-2, Rachel Gold et al., *Leveraging Advanced Metering Infrastructure to Save Energy* 30 (ACEEE Revised Jan. 27, 2020), *available at* https://www.aceee.org/sites/default/files/pdfs/u2001.pdf [hereinafter "ACEEE Report"].

[20] Michael Murray & Jim Hawley, More Than Smart & Mission:data Coalition, *Got Data? The Value of Energy Data Access to Consumers* 2 (Jan. 2016), *available at* https://static1.squarespace.com/static/52d5c817e4b062861277ea97/t/56b2ba9e356fb0b4c8559b7d/1454553838241/Got+Data+-+value+of+energy+data+access+to+consumers.pdf.

can help them understand when and how to use energy cost-effectively. They may also want to link their smart appliances and Home Area Network (HAN) devices to energy data.[21]

Q. Are there any privacy concerns related to sharing a customer's energy data?

A. Yes, energy data is personal to a customer. Accordingly, customers should have the opportunity to understand what information APS collects and the ability to maintain control over the use of their data.

Q. Is there an industry standard for energy data privacy?

A. Yes. The U.S. Department of Energy facilitated the development of a voluntary code of conduct ("VCC") entitled *Data Privacy and The Smart Grid: A Voluntary Code of Conduct* that describes how customer data should be treated to facilitate access while maintaining privacy.[22] The VCC establishes principles for data privacy that describe requirements for: customer notice and awareness, customer choice and consent, customer data access, data integrity and security, and self-enforcement management and redress.

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[21] *See, e.g.,* Ivan O'Neill, *Prices to Devices: Price Responsive Devices and the Smart Grid* (Southern California Edison 2010), *available at* https://www.oasis-open.org/committees/download.php/40684/Prices%20to%20Devices%20White%20Paper%20-%20101229.pdf.

[22] U.S. Dep't of Energy, *Voluntary Code of Conduct Final Concept and Principles* (Jan. 12, 2015), *available at* https://www.energy.gov/sites/prod/files/2015/01/f19/VCC%20Concepts%20and%20Principles%202015_01_08%20FINAL.pdf [hereinafter "Voluntary Code of Conduct"].

Q. What frequency of energy data does a customer need to make decisions about tariffs, energy efficiency, or other distributed energy products and services?

A. The more frequent and granular the better. Customers benefit from hourly data but receive more value from data reported on a 15-minute basis—and even more value from one-minute interval data. For example, if customers or service providers employ nonintrusive load monitoring (NILM), they can use meter data to identify which appliances are consuming how much energy by comparing the data with appliance signature databases. With one-minute meter data, NILM can identify as many as eight different appliance types.[23] This can help a customer identify the most cost-effective appliance replacements for reducing or shifting their energy consumption.

Q. Does the format of the energy data matter?

A. Yes, it does. If the energy data is available in a format that can be read by a computer, it is quicker to analyze. If the data is not machine-readable, it is cumbersome to scrutinize. Energy data is only valuable when it can be translated to useful or actionable information. If the energy data is in a standard format, it can be swiftly transformed to information that can inform customer investment and behavior.

Q. Is there an industry standard for energy data format?

A. Yes. The North American Energy Standards Board (NAESB) ratified the *Energy Service Provider (ESPI) Retail Energy Quadrant Book 21* (REQ.21) standard,

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[23] Attach. CR-2, ACEEE Report at 21.

commonly known at the Green Button standard, on April 8, 2019.[24] Compliance with this standard requires the energy data to be in Extensible Markup Language (XML). The data format portion of the standard is known as "Green Button Download My Data."

Q. What is the significance of XML formatted data?

A. XML is an open standard which can be used by a number of applications. It can also be used in a variety of databases and within different operating systems. Data in Excel spreadsheets can only be used in Excel. The restricted application options for Excel files impede the ability of customers or third parties to use the data efficiently.

Q. Is there an industry standard for sharing energy data?

A. Yes. NAESB REQ.21 also includes a standard for protecting customer privacy during the secure transmission of a customer's energy data to a third party. The data transmission portion of the standard is known as "Green Button Connect My Data." Green Button Connect My Data enables utilities to provide, at the direction of the customer, energy usage data to third parties in a consistent format. This allows customers to authorize the direct, secure transfer of their usage data to third-party service providers that can assist the customer in viewing, analyzing, and managing their energy consumption. Customers control the authorization process, defining the length of that authorization, and can revoke it at any time.

[24] Press Release, Green Button Alliance, *NAESB Ratifies Standard for Green Button* (Apr. 8, 2019), *available at* https://www.greenbuttonalliance.org/index.php?option=com_dailyplanetblog&category=technical.

Green Button Connect My Data enables customers the ability to share their energy usage data while protecting any personally identifiable information.

Q. How many utilities have implemented the Green Button standards?

A. To date, 35 U.S. utilities have committed to implementing the Green Button standards. An additional 38 U.S. companies providing third-party services have committed to Green Button standards. The totality of these commitments covers 60 million homes and businesses.[25]

Q. What happens if a customer's energy data does not comply with Green Button Connect My Data standards?

A. If a customer's energy data does not comply with NAESB REQ.21 (Green Button Connect My Data), then analysis is time-intensive and the transfer to a third party may not be secure or may disclose private or personal information. Customers may be reluctant to share energy usage data if personal information might be revealed. This adds friction to the interaction between the customer and the potential third-party energy services provider, delaying or derailing the interaction. Without access to the guidance and interpretation of data offered by third parties, customers may not be able to derive actionable information from their energy data.

[25] U.S. Dep't of Energy, *Green Button: Open Energy Data*, https://www.energy.gov/data/green-button#:~:text=What%20has%20been%20the%20success,signed%20on%20to%20the%20initiative (last visited July 30, 2020).

APS Customer Access to Energy Data Is Inadequate

Q. Has APS installed AMI meters for its customers?

A. Yes. APS has installed 1,125,293 residential AMI billing meters.[26]

Q. What type of customer energy data can the APS AMI meters generate?

A. Each of the 1,125,293 residential AMI billing meters records usage in 60-minute intervals.[27] APS currently has 290,618 residential meters that it could also configure to supply one-minute, five-minute, or 15-minute interval data.[28]

Q. If the APS residential AMI meters could generate customer energy data in intervals of one, five, or 15 minutes, why don't customers receive this energy data from APS?

A. APS has not installed the communications infrastructure necessary to transmit the data in more frequent intervals to APS.[29]

Q. Why hasn't APS installed the communications infrastructure necessary to provide customers access to more frequent and granular data?

A. When asked that question, APS responded that it "has not determined that the value of receiving the data in smaller time increments would offset the costs to implement."[30] However, APS also acknowledged that it has not actually evaluated the costs and benefits of installing the communications equipment.[31] Nor has APS

[26] APS Response to SC DR 4.1(b). All public discovery responses referenced in this testimony are compiled and available within Attachment CR-3 ["Attach. CR-3"].
[27] Attach. CR-3, APS Responses to SC DR 4.3(d) and 4.4(d).
[28] *Id.* at APS Response to SC DR 4.4(a).
[29] *Id.* at APS Response to SC DR 4.3(a), (b) and 4.4(a).
[30] *Id.* at APS Response to SC DR 5.1(a)(ii), (b)(ii).
[31] *Id.* at APS Response to SC DR 5.1(b).

considered any alternative to its identified, but unevaluated, solution for transmitting the data.[32]

Q. Does APS provide customers with their energy data in a format that complies with the Green Button Connect My Data standard (NAESB REQ.21)?

A. No.[33] The APS website does not provide customer data in an XML format. Nor does APS offer any means for a customer to obtain their energy data in XML format.[34]

Q. How does APS provide customers with their energy data?

A. APS provides customer energy data in an Excel file.[35] Because APS only offers energy data in Excel spreadsheet form, the data cannot be used outside of an Excel spreadsheet without manual conversion.

Q. How successful are residential customers in accessing their energy data using the APS website?

A. Fewer than 5 percent of APS residential customers access their monthly energy data.[36]

Q. Does APS provide customers with the ability to share their energy data in a format that complies with the Green Button Connect My Data standard (NAESB REQ.21)?

A. No.[37]

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[32] *Id.* at APS Response to SC DR 5.1(c).
[33] *Id.* at APS Response to SC DR 4.7.
[34] *Id.* at APS Response to SC DR 4.6(b).
[35] *Id.* at APS Response to SC DR 4.6(a).
[36] *Id.* at APS Response to SC DR 4.2(a), (c).

Q. How can APS customers share their energy data with a third-party provider of energy products and services?

A. A customer may register on aps.com to create and download three reports: current usage, last billed usage, and peak usage data. They can then send these reports to anyone they wish. The customer may also grant guest access to their account on aps.com for up to five guests.

Q. What energy data can a guest view?

A. Guests can view customer account information, usage graphs, charges, and bills. This includes sensitive customer-saved bank account information and utility account balances.[38]

Q. How does APS protect a customer's privacy from a guest user of their account?

A. APS does not protect a customer's private account information from a guest user. APS does not provide customers any means to share energy usage data with a guest without sharing personal account information as well, including saved bank account information or their utility account balance.[39]

Q. Does an APS guest user account comply with U.S. Department of Energy's Data Privacy and The Smart Grid: A Voluntary Code of Conduct?

A. No. The VCC establishes that a customer should have a degree of control over their customer data which includes both customer energy usage data and account

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[37] *Id.* at APS Response to SC DR 4.7.
[38] *Id.* at APS Response to SC DR 5.4(a), (b).
[39] *Id.* at APS Response to SC DR 5.4(a), (b).

data. Customer energy usage data is a customer's measured energy usage but does not identify the customer, while a customer's account data includes information personal to a specific customer such as their name, address, dates of service, phone, email, bank account numbers, and meter numbers. The VCC requires that a customer be allowed to authorize different types of disclosure among multiple third parties and to limit disclosure to just that data to only that authorized third party. As discussed above, APS does not provide any means for a customer to limit a guest user to energy usage data only.

Q. How many APS customers have successfully shared their energy data?

A. That information is unknown because APS does not track it.[40] However, given that only about 5 percent of APS residential customers access their energy data via the APS portal on a monthly basis and that guest users would be included within this number, we know that very few APS customers have successfully shared their energy data via the portal.

Q. How does APS noncompliance with the NAESB REQ.21 Standard (Green Button Connect My Data standard) impact customers?

A. APS's failure to create a seamless method for customers to authorize the secure and private transfer of their energy data to potential service providers inhibits a customer's ability to adopt distributed energy resources or secure other energy saving products and services. As I described above, if a customer's energy data does not comply with NAESB REQ.21, then analysis is time-intensive and the

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[40] *Id.* at APS Response to SC DR 4.9.

transfer to a third party may not be secure or private. APS customers do not have an easy mechanism to transfer their energy usage data, and just that data, to a third party in a secure fashion. This may make them reluctant to share data. This adds friction to the interaction between the customer and the potential third-party energy services provider, delaying or derailing the interaction. Without access to the guidance and interpretation of data offered by third parties, customers may not be able to derive actionable information from their energy data.

Q. Does APS support customers in identifying individualized products or services that would benefit that customer, using the customer's personal energy data?

A. APS did develop a rate analysis tool to guide customers to the tariff option that was best for their energy use profile as part of the 2017 rate case. The tool, however, was materially flawed, resulting in a public apology by APS and a pledge to issue refunds funded by shareholders to affected customers.[41] APS does not currently appear to provide any other customer-specific support regarding use of personal energy data.

Recommendations Regarding APS Proposal for Default Bill Simplification and Customer Data Access

Q. Do you have a recommendation about the APS proposal for default bill simplification?

A. Yes. The Commission should reject the APS proposal for default bill simplification. APS has not presented sufficient evidence to support what would

[41] Alexander Report at 7.

function as a permanent waiver of the consumer information protections of A.C.C. R14-2-210. When or if customers have access to their energy data in a form compliant with NAESB REQ.21, it may be appropriate to consider a rule amendment.

Q. Does APS's incident with its rate comparison tool evoke any additional insights?

A. Yes. It is critical that customers receive the energy data in a form that is useful to them so that they can make informed decisions. As I discussed previously, the value of the data will likely come from the activities of utilities, technology companies, and service providers who process, analyze, and perhaps even act upon the energy data on behalf of the customer. It is APS's responsibility to help customers understand and act upon their energy data, and they should be held to account if they do not perform those responsibilities well, but customers should also be able to seek guidance outside of the utility from whomever they choose.

Q. Do you have any recommendations for Commission action that could help to ensure customers receive the energy data they need to make informed decisions or to engage the assistance of third-party service providers who will guide them or act on their behalf?

A. Yes. APS customers have paid for the AMI infrastructure. They should receive value for it. I recommend that the Commission direct APS to implement NAESB REQ.21, Green Button Connect My Data, as soon as practicable.

Q. Do you have any recommendations for Commission action regarding the protection of customer privacy?

A. Yes. I recommend that the Commission direct APS to comply with the U.S. Department of Energy's *Data Privacy and the Smart Grid: A Voluntary Code of Conduct*.[42]

Q. Do you have any recommendations about the energy data available from AMI meters?

A. Yes. As I previously explained, the more frequent and granular the data, the more valuable it is. I recommend that the Commission direct APS to investigate and report on whether the investment required to provide more granular data in the form of one-, five-, or 15-minute intervals to customers would be cost-effective.

Q. Do you have any other recommendations?

A. Yes. I also recommend that the Commission direct APS to track and report quarterly metrics that will inform the Commission, APS, and customers on APS's progress toward leveraging the benefits of AMI for its customers. These metrics should include the three metrics identified by ACEEE for AMI deployment:[43]

- Customer usage of energy portal; one-time or regular access
- Number and percentage of customers opting out of or taking a price offering
- Number of third parties that successfully access customer data through Green Button Connect or other utility data-sharing method: percentage of customers able to authorize third-party service company requests on first attempt (target:

[42] Voluntary Code of Conduct.
[43] Attach. CR-2, ACEEE Report at 28, Table 4.

95 percent); percentage of time third-party service provider receives access when authorized by customers (target: 95 percent)

Q. Are there any other metrics that APS should track?

A. Yes. I also recommend that the Commission require APS to track and report metrics recommended in the Alexander Report:

- Customer-initiated changes to their rate plans
- APS-initiated changes to customer rate plans
- Number of customers not on the "best" or "most economical rate" by rate class
- Frequency and type of complaints
- Call Center performance[44]
- Results of customer research on messaging and bill presentment
- Enrollment for limited-income programs
- Achievement of participation objectives for demand-side management programs
- Analysis of the impact of rate design on system benefits, such as peak load reduction and lower generation supply costs
- Key indicia of credit and collection activities, such as disconnection notices, disconnections, and payment arrangements.[45]

[44] APS witness Leland Snook suggested that an appropriate Call Center performance metric could be an internal customer satisfaction metric, which is conducted among both residential and business customers who have recently interacted with APS in the Call Center, on the IVR or on aps.com. *See* Direct Testimony of Leland R. Snook at 23:24-27 [hereinafter "Snook Direct"].

[45] Alexander Report at 36-37.

IV. APS'S FORMULA RATE CONCEPT ALTERNATIVE

Q. What is APS's Formula Rate Concept Alternative?

A. APS offers, but does not propose, a Formula Rate Concept Alternative.[46] Mr. Snook testified that:

> A formula rate provides incremental annual adjustments to rates, based on agreed upon, Commission-approved inputs to a formula that are established during a rate case. With the agreed upon structure in place, inputs are updated and reviewed annually and rates are adjusted accordingly.[47]

Q. How would the rates be adjusted on an annual basis under the APS Formula Rate Concept Alternative?

A. APS proposes to forecast its expenses and then true them up to actual expenses each year. That is, APS will project what it expects to spend, but if it spends more, the rate would be adjusted to cover the extra expense. If it spends less, then the money is returned to customers after the reconciliation. However, the forecasted budget only operates as a targeted spending level because there is no incentive to spend less and no penalty for spending more.

Q. What purpose does APS give for offering this Formula Rate Concept Alternative?

A. Mr. Snook has testified that "there has been discussion in a number of regulatory proceedings about the pros and cons of adjustor mechanisms. With a formula rate

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[46] Snook Direct at 24:3-10.
[47] *Id.* at 22:20-23.

option, APS is offering an alternative that could also provide similar benefits to all parties involved while also simplifying future ratemaking process."[48]

Q. Why does APS offer the Formula Rate Concept Alternative, if it is not proposing to adopt it?

A. Mr. Snook has testified that APS is satisfied with the existing adjustors, which serve to track actual expenses in seven different categories. [49]

Q. What benefits does APS suggest would result from the Formula Rate Concept Alternative as APS has framed it?

A. Mr. Snook suggests that the Formula Rate Concept Alternative would provide an opportunity for the Commission to scrutinize APS's earnings annually and provide an immediate avenue for the Commission to incrementally adjust rates. It would eliminate five of APS's seven adjustor mechanisms, improve rate gradualism, and decrease regulatory lag. He suggests that it could potentially increase time between rate cases.[50]

Q. What design elements has APS included within its Formula Rate Concept Alternative?

A. APS proposes that its Formula Rate Concept Alternative would include a commitment to refrain from filing a rate case for three to seven years. The scope of the formula would include all costs except fuel (Power Supply Adjustment charge or "PSA") and FERC jurisdictional costs (Transmission Cost Adjustment charge or "TCA"). It would retain the same authorized return on equity ("ROE")

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[48] *Id.* at 24:6-10.
[49] *Id.* at 24:4-10.
[50] Snook Direct at 22-23:26-9, Attachment LRS-4DR.

and capital structure throughout its term, but the cost of debt would be updated annually. The revenue resulting from the formula rate would be adjusted based upon forecasted plant and depreciation with a true up to actual plant and depreciation. APS does not propose a "Dead Band"[51] around its ROE. It would commit to an annual limit on increases of 2.5 percent.[52]

Q. Does APS propose any performance mechanisms within its Formula Rate Concept Alternative?

A. APS does not propose any performance mechanisms with financial consequences. It does propose two performance metrics: Reliability as measured by the System Average Interruption Frequency Index ("SAIFI"); and Customer Satisfaction as measured by an internally tracked metric related to Call Center service.[53]

The Value of Alternative Regulatory Mechanisms

Q. Mr. Snook has indicated that APS sees some interest in Arizona for an alternative to existing adjustor mechanisms and value in simplifying future ratemaking processes. Do you see value in considering alternative regulatory mechanisms?

A. Yes. Many jurisdictions are considering alternatives to traditional cost-of-service regulation. This interest is driven by a combination of the changing electric industry landscape and public policy.

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[51] APS does not define a "dead band" but it is typically understood to include a range of value above and below the ROE which would not trigger any action.
[52] Attachment LRS-4DR (provided with Snook Direct).
[53] Snook Direct at 23:12-27.

Q. What is the nature of the changes within the electric utility industry?

A. The nation's electricity system is, by necessity, transforming rapidly. As a result of interacting economic, technology, and policy factors, U.S. energy-related carbon dioxide emissions have fallen over the past decade.[54] From the perspective of centralized electricity generation, a massive and dynamic reduction in the price of natural gas as well as falling prices in wind and solar generation have supplanted coal-fired generation and even nuclear generation.[55] Additionally, roughly half of all growth in U.S. renewable electricity generation and capacity since 2000 is associated with state renewable portfolio standards.[56] In short, market- and policy-driven changes in fuel choices for centralized electricity generation have markedly shifted the energy landscape.

Q. Are there any other changes underway in the electricity industry?

A. Yes. The change in fuel for large- or utility-scale electricity generation units is not the only part of the transformation. The centralized, utility-scale generation that provided the last century of energy is no longer the only practical option. The costs of distributed generation technologies such as solar photovoltaics and battery storage are falling, resulting in increasing number of customers investing in their own grid-connected resources.[57] Communications and computer analytical

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[54] Perry Lindstrom, *EIA expects U.S. energy-related CO_2 emissions to decrease annually through 2021*, U.S. Energy Info. Admin. (Jan. 17, 2020), https://www.eia.gov/todayinenergy/detail.php?id=42515.

[55] U.S. Energy Info. Admin., U.S. Dep't of Energy, *Annual Energy Outlook 2019* (Jan. 24, 2019), *available at* https://www.eia.gov/outlooks/aeo/pdf/aeo2019.pdf.

[56] Galen L. Barbose, *U.S. Renewables Portfolio Standards: 2018 Annual Status Report* (Lawrence Berkeley National Laboratory Nov. 2018), *available at* https://emp.lbl.gov/publications/us-renewables-portfolio-standards-1.

[57] *Solar Industry Research Data*, Solar Energy Industries Association, https://www.seia.org/solar-industry-research-data (last visited Sept. 16, 2020).

capabilities make it possible for high penetrations of renewable resources to be integrated into the grid.[58] Energy productivity is also rising. Between 1990 and 2015, the United States has grown its gross domestic product while using less energy year over year, becoming more energy efficient.[59] The electricity system is transforming from a one-way power delivery network in which customers passively receive electricity to a two-way flow of both power and information in which customers both receive and produce electricity. The two-way system is brought to life by customers who receive information about their usage (when and how much they use) and price signals indicating moment-by-moment the value of electricity and incentivizing customer usage behavior.

Q. Are these changes in the electricity utility industry occurring within Arizona?

A. Yes. In fact, the Commission has a docket considering possible modifications to the Commission's energy rules to explore subjects integral to this energy transition.[60] These include: the renewable energy standard, electric energy efficiency standards, net metering, resource planning and procurement, retail electric competition, electric vehicles, interconnection of distributed generation facilities, blockchain technology, technological developments in generation and

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[58] Yang Zhang, Tao Huang & Ettore Francesco Bompard, *Big data analytics in smart grids: a review,* 1 Energy Informatics (2018)*, available at* https://energyinformatics.springeropen.com/articles/10.1186/s42162-018-0007-5.

[59] *GDP per unit of energy use (constant 2017 PPP $ per kg of oil equivalent) - United States*, World Bank, https://data.worldbank.org/indicator/EG.GDP.PUSE.KO.PP.KD?end=2015&locations=US&start=1990&view=chart (last visited Sept. 16, 2020).

[60] Memorandum: Request for a New Docket, Docket No. RU-00000A-18-0284 (Ariz. Corp. Comm'n Aug. 17, 2018), *available at* https://docket.images.azcc.gov/0000191382.pdf.

delivery of energy, forest bioenergy, and baseload security.[61] As part of that docket, the Commission has issued an Electric Vehicle Policy Implementation Plan.[62]

Q. Are there public policy reasons in Arizona to consider alternative regulatory mechanisms?

A. Yes. There is an emerging consensus for decarbonization of Arizona electric utilities for both climate and cost-effectiveness reasons. It appears that it is the position of the majority of the Commission that Arizona electric utilities should achieve 100 percent clean energy by 2050 and 35 percent energy efficiency by 2030.[63] Commissioner Sandra D. Kennedy has stated, "the science is clear regarding the need for aggressive decarbonization."[64] Commissioner Kennedy also cites data supporting that Arizona would enjoy economic and reliability benefits from a decarbonization policy.[65] Commissioner Justin Olson has stated that "because renewable energy in many cases is now the most cost-effective method of generating electricity, requiring utilities to invest in the most cost-effective methods would lead to significant increases in renewable energy

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[61] *Id.*

[62] Electric Vehicle Policy Implementation Plan, Docket No. RU-00000A-18-0284 (Ariz. Corp. Comm'n July 19, 2019), *available at* https://docket.images.azcc.gov/0000199128.pdf.

[63] Mar. 25, 2020 Letter from Chairman Burns; *see also* Letter from Commissioner Peterson, Docket No. RU-00000A-18-0284 (Ariz. Corp. Comm'n Mar. 20, 2020), *available at* https://docket.images.azcc.gov/E000005457.pdf (regarding 100% clean energy by 2050).

[64] Letter from Commissioner Kennedy at 1, Docket No. RU-00000A-18-0284 (Ariz. Corp. Comm'n Mar. 25, 2020), *available at* https://docket.images.azcc.gov/E000005582.pdf.

[65] *Id* at 2.

deployment."[66] Chairman Burns has indicated that the Energy Rules should also incorporate more robust renewable and distributed energy standards.[67]

Q. Are there any factors specific to APS that may indicate alternative regulatory mechanisms are worth considering?

A. Yes. As I mentioned previously, this rate case was precipitated by a Commission order finding, among other matters, that APS Customer Outreach and Education Program ("COEP") was so ineffective as to require "Staff to select and hire an independent consultant, paid for by APS, to develop a program to properly and adequately educate customers on all aspects of APS's rate plans."[68]

Q. Would alternative regulation improve utility regulation in Arizona relative to the status quo?

A. It might. Alternative regulation could ensure that electric utilities navigate the changes underway in the electricity industry while continuing to provide cost-effective, universal service. To achieve this, utilities must successfully harness and optimize all available technologies, some of which they will own but others will be owned by their customers or third parties. Continuing to reward utilities for investing in assets that they own would maintain the utilities' existing financial disincentive to support clean, distributed energy technologies, which are often not part of a utility's rate base. Alternative forms of regulation could help a

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[66] Letter from Commissioner Olson at 1, Docket No. RU-00000A-18-0284 (Ariz. Corp. Comm'n Mar. 23, 2020), *available at* https://docket.images.azcc.gov/E000005533.pdf.
[67] Mar. 25, 2020 Letter from Chairman Burns.
[68] Order No. 77270 at 8:12-15, Docket No. E-0134A-19-0003 (Ariz. Corp. Comm'n June 27, 2019), *available at* https://docket.images.azcc.gov/0000198805.pdf.

utility thrive during the transition underway, contain costs, achieve public policy goals such as decarbonization, and improve utility performance.

Formula Rate Concept Is Not the Right Choice for Arizona

Q. Would the Formula Rate Concept Alternative offered by APS improve regulation in Arizona relative to the status quo?

A. No. The Formula Rate Concept Alternative does nothing to address ongoing changes within the electricity industry. It would not provide additional tools to address public policy goals around decarbonization and makes no meaningful contribution to APS performance. Most significantly, it would reduce cost-containment features that exist under current cost-of-service regulation in Arizona.

Q. How would the Formula Rate Concept Alternative offered by APS reduce the cost-containment features of existing Arizona utility regulation?

A. As Mr. Snook acknowledges, Commissions have rarely adopted formula rates outside of FERC.[69] This is largely due to recognition by Commissions that formula rates have a "tendency to shift financial risks toward customers, a concern that automatic adjustments may curtail the thorough review of utility costs, and reduced incentives for utilities to control costs."[70] These concerns have been borne out by experience in jurisdictions where formula rate plans ("FRPs") have been implemented. For example, in 2015, Act 725 in Arkansas required that the Commission approve FRPs and capped revenue increases under an FRP to 4

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[69] Snook Direct at 24:3-4.
[70] Order No. 89226 at 53, Case No. 9618 (Md. Pub. Serv. Comm'n Aug. 9, 2019).

percent per year. Following passage of the Act, Entergy Arkansas, Inc. filed for an FRP. After implementation of FRPs in Arkansas, the General Staff of the Arkansas Public Service Commission observed that:

> An FRP is an annual rider. It fundamentally accomplishes a higher level of certainty of recovery thus reducing risk to the utility…. The ability to increase revenues 4% each year is a considerable risk reduction for the utility.[71]

Q. Does the experience in Arkansas or elsewhere provide an opportunity for lessons learned concerning the likelihood that a formula rate plan will operate to contain costs?

A. Yes. Turning to the Arkansas experience, the FRP implementation there eviscerated the Commission's ability to control costs. Customers experienced maximum increases each year of the plan. The Arkansas Staff's report explained how that FRP operated to the detriment of customers:

- It reduces the time afforded for review of utility costs, which can serve to incentivize spending as compared to a regulatory framework where more time is afforded to scrutinize costs.
- It allows projections on projections, which incentivizes spending as compared to a regulatory framework where projections are based on historical information modified by known and measurable changes. The effect of this is compounded by the reduced opportunity to review expenditures.
- It incentivizes spending due to the annual rate adjustments. Once the FRP framework is selected by a utility, an outcome of a 4 percent increase each year (over the prior year) is less subject to challenge as long as the costs are prudently incurred and calculated in accordance with the tariff. The traditional

[71] General Staff's Initial Brief Pursuant to Order No. 18 at 17, Docket No. 16-036-FR (Ark. Pub. Serv. Comm'n Jan. 1, 2019), *available at* http://www.apscservices.info/pdf/16/16-036-FR_382_1.pdf.

regulatory tools in the Arkansas Commission are more limited under the FRP framework, as the Commission has recognized.

- The unstated implication of the FRP statute is that the risk of an earnings review is effectively eliminated. There is no clear incentive to contain costs between annual FRP 4 percent increases. While the FRP framework states the rate change may be an increase or a decrease, the likelihood of a decrease is highly unlikely.[72]

Q. Why have you stated that the APS Formula Rate Concept Alternative does not address the changes in the electric industry?

A. One of the major challenges for traditional cost-of-service utility regulation during the changes underway in the electric industry is that it encourages utility behavior that we needed for the past century, not the utility behavior we need for the coming decades. What I mean by this is that for the first century of utility regulation, demand was growing. Our country required more generation plants and transmission and distribution lines as quickly as they could be built. Utility regulation was designed to reward utilities for investing in that growth. Utilities were (and are largely still) paid for investing, not for the results they deliver. Going forward, for cost-effective universal service to remain a reality, utilities must harness all of the technologies that are available, some of which they will own but others will be owned by their customers or third parties. Continuing to reward utilities for investing in assets that they own would maintain the utilities' existing financial disincentive to support clean, distributed energy technologies. This is colloquially known as the utility's "capital bias." That is, the utility has a

[72] *Id.* at 18-19.

financial incentive to invest, regardless of whether a utility investment is the optimum solution for cost-effective universal service. Nothing in APS's Formula Rate Concept Alternative addresses this challenge.

Q. Please explain why the APS Formula Rate Concept Alternative would not advance Arizona's public policy better than the status quo.

A. For Arizona to be successful in decarbonizing its electricity grid, it will need to tap all available clean energy solutions. Once again, some of those resources will be owned or controlled by their customers or third parties. The APS Formula Rate Concept Alternative exacerbates the utility incentive to invest in its own traditional assets by codifying into a formula the same flawed incentive structure—where the revenue requirement would be based on the utility's rate base and authorized equity return on that rate base—the "capital bias." In fact, the APS Formula Rate Concept strengthens the problematic connection with the reward for investment by assuring the utility it will always receive its authorized return on equity and by weakening prudency review.

Q. Why did you suggest that the APS Formula Rate Concept Alternative would not improve APS performance?

A. APS proposes to add only two metrics, with no financial consequence, to its Formula Rate Concept Alternative. To the extent that the addition of these metrics would improve APS performance, they could be added with or without the adoption of APS Formula Rate Concept Alternative.

Q. Do you have a recommendation regarding the APS Formula Rate Concept Alternative?

A. Yes. The Commission should reject consideration of the APS Formula Rate Concept Alternative. It does not improve upon the status quo. The Formula Rate Concept Alternative does nothing to address changes within the electricity industry. It would not provide additional tools to address public policy goals related to decarbonization and makes no meaningful contribution to performance. Most significantly, it would reduce cost-containment features that exist under current cost-of-service regulation in Arizona.

Q. Would some modification of the APS Formula Rate Concept Alternative be worth considering?

A. No. I recommend that the Commission not pursue any Formula Rate structure. They have not advanced the decarbonization of the energy grid and have largely caused customers to experience unnecessary rate increases. I do not see any formula rate construct being an improvement on status quo regulation in Arizona.

Comprehensive Performance-Based Regulation Would Improve the Status Quo

Q. You have indicated that Arizona could benefit from considering alternative regulatory mechanisms, but you have rejected consideration of formula rate plans. What alternative regulatory mechanisms would you recommend that Arizona consider?

A. I recommend that the Commission consider adopting performance-based regulation. Performance-based regulation includes several elements intended to strengthen utility performance incentives that can be used alone or together.[73] These include multi-year rate plans ("MRPs") and performance incentive mechanisms ("PIMs"). MRPs in combination with well-crafted metrics, scorecards, and financial incentive mechanisms can be powerful drivers toward cost-effective, decarbonized energy systems.

Q. What are the key features of a Multi-Year Rate Plan?

A. MRPs are widely used around the world and have been in place for many decades in a variety of industries. MRPs are also known as "price cap regulation" or "revenue cap regulation." These approaches have also been referred to as "hands-off regulation" because the utility's costs are not closely examined during the duration of the plan.[74] MRPs cap utilities' allowed revenue and allow utilities to keep a portion of cost savings during the rate plan period. In doing so, they help to shift utility financial incentives away from the bias toward capital investment and increasing rate base.[75] Instead, the utility's revenues are de-linked from its actual costs in combination with a rate case moratorium (typically lasting from three to five years). Revenues can be adjusted annually for changing business conditions such as inflation or customer growth during the life of the plan based. These changes can be based on an index or a cost forecast at the outset of the rate plan.

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[73] Mark Newton Lowry & Tim Woolf, *Performance-Based Regulation in a High Distributed Energy Resources Future* 1 (Lisa Schwartz eds. Lawrence Berkeley National Laboratory Jan. 2016), *available at* https://emp.lbl.gov/sites/all/files/lbnl-1004130_0.pdf [hereinafter "Performance Based Regulation Report"].

[74] *See generally* Attachment CR-4, Melissa Whited & Cheryl Roberto, *Multi-Year Rate Plans: Core Elements and Case Studies* (prepared for Maryland PC51 and Case 9618 Sept. 30, 2019), *available at* https://www.synapse-energy.com/sites/default/files/Synapse-Whitepaper-on-MRPs-and-FRPs.pdf.

[75] Performance Based Regulation Report at 41.

Q. What are the benefits of a Multi-Year Rate Plan?

A. MRPs can reduce the frequency of rate cases, improve the culture of utility management, improve utility performance, reduce the capital bias, and lower utility costs. One of the most important benefits is that an MRP requires and facilitates planning over a multi-year horizon on a fully integrated basis. Unlike a mechanism that reconciles actual costs, this type of planning and cost recovery provides better signals to the utility to operate efficiently. Instead of the utility passing expenses directly to customers, as is done under the current rate setting model, the utility will experience the budget as its own money at risk. That is, if the utility achieves the objectives under budget, the utility is rewarded by the ability to retain the savings. Additionally, revenues escalate between rate cases independently of the size of rate base or the return on equity, thereby softening the utility's natural bias to make capital investments to increase rate base.

Q. How does it differ from a Formula Rate Plan?

A. Both MRPs and FRPs feature formulas, thereby creating some confusion regarding the differences between the two approaches. The primary distinction is that FRPs formulaically ensure that revenues track costs, often measured as deviations in the return on equity from the utility's authorized return on equity. If a utility's earned return is above its authorized return on equity, it will be required to reduce its rates. Likewise, if a utility's earned return is below its authorized return on equity, the Commission will permit the utility to increase its rates. In contrast, MRPs do not reconcile revenues to actual costs. Rather, the utility must operate within its authorized revenue amounts and is rewarded for finding the most cost-effective solutions for serving customers.

Robust Performance Incentive Mechanisms Are Valuable Additions

Q. You mentioned that performance incentive mechanisms should be part of a comprehensive performance-based regulation approach. Why is it important to include performance mechanisms in a Multi-Year Rate Plan?

A. Under an MRP framework, utilities retain some or all of the savings achieved through cost reductions. This can create an incentive to cut costs at the expense of service quality. To combat this incentive, regulators have historically coupled MRPs with PIMs to prevent service quality degradation. PIMs are also increasingly being used to promote other outcomes such as emissions reductions, as well as to ensure that a utility follows through on its commitments such as investments in grid modernization.

Q. Please briefly describe performance incentive mechanisms.

A. PIMs are Commission-established regulatory requirements that target achievement of specific outcomes.[76] As a foundational step, Commissions must identify regulatory policy goals together with desired performance objectives or outcomes. Once the Commission establishes the desired outcomes, it may establish PIMs at three levels of weight to motivate attainment of those outcomes: metrics, targets, or financial incentives. Metrics are the building blocks of PIMs.

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[76] *See generally*, Melissa Whited, Tim Woolf, & Alice Napoleon, *Utility Performance Incentive Mechanisms: A Handbook for Regulators* (prepared for the Western Interstate Energy Board Mar. 9, 2015), *available at* https://www.synapse-energy.com/sites/default/files/Utility%20Performance%20Incentive%20Mechanisms%2014-098_0.pdf.

In the first instance, a utility measures outcomes or outputs related to its operations. These measurements are metrics. When it is possible to define a desired level of performance based on baseline metrics, the Commission can establish a target for improvement. The metrics are subsequently compared against the target. Sometimes this simply occurs on a "scorecard" to track and inform how a utility is executing its responsibilities. In other instances, the utility receives positive or negative financial consequences (incentives) for established levels of performance relative to the target. A variation on a financial incentive is a shared savings mechanism. When a utility is able to accomplish an outcome at lower cost than alternatives, the utility is given an opportunity to "share" in the savings as an incentive for the efficient behavior.

Q. Are Performance Incentive Mechanisms useful outside of a Multi-Year Rate Plan?

A. Yes. PIMs can improve regulation as a part of traditional cost-of-service regulation. Performance incentives can be used to express regulatory expectations and connect those expectations with financial consequences inside an MRP or as part of traditional cost-of-service regulation.

Q. Are PIMs Being Considered in Arizona?

A. Yes. At Commissioner Lea Márquez Peterson's request,[77] the Commission has already opened an investigation into the role of PIMs.[78] Commissioner Boyd

[77] Commissioner Márquez Peterson Request for New Docket, Docket No. E00000A-20-0019 (Ariz. Corp. Comm'n Feb. 6, 2020), *available at* https://docket.images.azcc.gov/0000200847.pdf.

Dunn has also suggested that performance-based rate design should be considered in this rate case.[79] He has requested that parties "consider and present evidence on whether a penalty or incentive-based ROE that is tied to meeting specific customer satisfaction, education, and outreach metrics is just, reasonable, and in the best interest of ratepayers." [80] Commissioner Dunn has directed that the "evidence presented should weigh pros and cons of moving to this type of a rate design and discuss possible scenarios for a performance-based metric."[81] He directed parties to "(1) identify the scope of the customer satisfaction, education, and outreach problems, (2) propose and discuss possible metrics for tracking and reporting performance on customer satisfaction, education, and outreach (3) propose and discuss performance targets, and (4) propose and discuss the financial penalty structure."[82]

Q. Do you recommend the Commission adopt a comprehensive performance-based regulation plan with a multi-year rate plan and performance mechanisms in this docket?

A. No. While the Commission may ultimately find that an MRP with performance mechanisms is in the public interest, I recommend that the Commission establish a separate docket to investigate comprehensive performance-based regulation.

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[78] *In the matter of the investigation of the Arizona Corporation Commission into the Role of Performance Incentive Mechanisms in regulated investor owned electric utility rate cases in Arizona,* Docket No. E-00000A-20-0019 (Ariz. Corp. Comm'n 2020).
[79] Letter from Commissioner Dunn (Ariz. Corp. Comm'n June 17, 2020), *available at* https://docket.images.azcc.gov/E000007101.pdf.
[80] *Id.* at 2.
[81] *Id.*
[82] *Id.*

Q. Is there any action that you would recommend the Commission take within this docket?

- Yes. I recommend that the Commission direct APS to begin tracking metrics. The design and implementation of an effective MRP deserve a thoughtful and robust process as part of the Commission's forthcoming investigation into performance-based regulation. PIMs, however, have long been incorporated into both MRPs and into cost-of-service-based regulation. PIMs offer the advantage of being able to be implemented incrementally and iteratively. It is appropriate to consider PIMs once the Commission identifies a regulatory policy goal and desired performance objectives or outcomes. As I have previously testified, it would be appropriate for the Commission to direct APS to begin tracking metrics now. This data will inform the investigation regarding PIMs. At the very least, these metrics should include those I recommend above related to energy data. I also recommend adding a simple metric for energy efficiency: APS should report the kWhs of energy it assists customers in saving relative to the kWhs of energy it sells.

Investigation of Performance-Based Regulation

Q. If the Commission were to undertake a separate investigation of performance-based regulation, do you have any recommendations for the questions they should entertain?

A. Yes. I have attached to my testimony as Attachment-CR5, "Utility Model: Questions For Regulators And Stakeholders To Ask And Answer As Utilities Evolve."[83] This list was developed by Energy Innovation and provides a good start to the regulatory conversation considering the changes underway in the electricity industry.

[83] Attachment CR-5, Ron Lehr & Sonia Aggarwal, *Utility Models: Questions for Regulators and Stakeholders to Ask and Answer as Utilities Evolve* (Energy Innovation Feb. 2017), *available at* https://energyinnovation.org/wp-content/uploads/2017/02/UtilityRegModels_QuestionsList.pdf.

Q. Do you have any recommendation regarding the process the Commission may use to conduct an investigation of performance-based regulation?

A. I recommend the Commission ensure that the forthcoming investigation allows for a robust discussion involving stakeholders that begins with an articulation of what customers, the larger community, and Arizona want to see from their electric utilities. Then, it would be appropriate to conduct an assessment of the opportunities for performance-based regulation to address to achieve these goals, relative to the existing cost-of-service structure.

Recommendations Regarding APS Formula Rate Concept Alternative

Q. To summarize, what are your recommendations for APS Formula Rate Concept Alternative?

A. My recommendations for the Commission are as follows:

- The Commission should reject consideration of the APS Formula Rate Concept Alternative. It does not improve upon, and would, in fact, entrench, the status quo. The Formula Rate Concept Alternative does nothing to address changes within industry. It would not provide additional tools to address public policy goals around decarbonization and makes no meaningful contribution to performance. Most significantly, it would reduce cost-containment features that exist under current cost-of-service regulation in Arizona.
- The Commission should not pursue any Formula Rate structure. Such structures have not demonstrably advanced the decarbonization of the energy grid and have largely caused customers to experience unnecessary rate increases. I do not see any formula rate construct being an improvement on status quo regulation in Arizona.
- The Commission should consider adopting performance-based regulation. Performance-based regulation includes several elements intended to strengthen

utility performance incentives that can be used alone or together. These include MRPs and PIMs. MRPs in combination with well-crafted metrics, scorecards, and financial incentive mechanisms can be powerful drivers toward cost-effective, decarbonized energy systems.

- I recommend that the Commission investigate comprehensive performance-based regulation in Docket No. E-00000A-20-0019.

- I recommend that the Commission direct APS to begin tracking performance metrics. The design and implementation of an effective MRP deserves a thoughtful and robust stakeholder process as part of the Commission's forthcoming investigation into performance-based regulation. PIMs, however, have long been incorporated into both MRPs and into cost-of-service-based regulation. PIMs offer the advantage of being able to be implemented incrementally and iteratively. It is appropriate to consider PIMs once the Commission identifies regulatory policy goals and desired performance outcomes. It would be appropriate for the Commission to direct APS to begin tracking metrics now. This data will inform the investigation regarding PIMs. At the very least, these metrics should include those I recommended related to energy data on starting on page 28. To those I would add a simple metric for energy efficiency: APS should report the kWhs of energy it assists customers in saving relative to the kWhs of energy it sells.

V. <u>RATEPAYER-BACKED SECURITIZATION</u>

Q. What is ratepayer-backed securitization?

A. At its core, ratepayer-backed securitization is refinancing. Just as a homeowner may benefit from refinancing their home mortgage when interest rates drop, the utility can reduce its traditional financing costs, and save customers money, by meeting some of its capital needs using less expensive ratepayer-backed bonds.

Q. What are ratepayer-backed bonds?

Ratepayer-backed bonds are loans to the utility that customers have a legally enforceable obligation to repay through monthly surcharges on their utility bills.

Q. How does ratepayer-backed securitization work?

A. Fundamentally, ratepayers "buy out" a portion of the utility investors' investment in the utility's debt and equity, replacing the higher cost capital with lower cost capital raised on the ratepayers' obligation to pay. To accomplish this, a Commission must issue a finance order that authorizes the issuance of ratepayer-backed bonds.[84] Then the proceeds of the bonds are used to replace the higher cost capital on the utility's balance sheet. The finance order must authorize the utility to charge its customers sufficient revenue to service the bonds and this charge must be adjustable to account for revenue changes over time necessary to ensure the bonds are repaid. Customers may not avoid or "bypass" this charge. The Commission order must be irrevocable. These payments are assigned to and

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[84] A number of state legislatures have enacted laws providing explicit authorization to the state utility regulatory commission to issue finance orders for securitization for specifically enumerated purposes. As a constitutionally authorized body, however, the Arizona Corporation Commission has been granted the "full power to, and shall, prescribe just and reasonable classifications to be used and just and reasonable rates and charges to be made and collected, by public service corporations within the state for service rendered therein, and make reasonable rules, regulations, and orders by which such corporations shall be governed in the transaction of business within the state, and may prescribe the forms of contracts and the systems of keeping accounts to be used by such corporations in transacting such business, and make and enforce reasonable rules, regulations, and orders for the convenience, comfort, and safety, and the preservation of the health, of the employees and patrons of such corporations." *See* Ariz. Const. art. XV, § 3. Thus, it appears that the Arizona Corporation Commission has plenary authority to issue finance orders it deems necessary to provide just and reasonable rates.

flow through a limited purpose bankruptcy-remote entity set up for the sole purpose of the transaction that is responsible for paying the bondholders.[85]

Q. What makes the customer repayment obligation for ratepayer-backed bonds legally enforceable?

A. To establish a ratepayer-backed bond, the regulatory commission must issue a financing order that creates a non-bypassable tariff to collect the revenue necessary to service the bond from the customers of a distribution system. These payments flow through a legally separate corporate organization that cannot be held responsible for the debts of the utility.

Q. Why would ratepayer-backed bonds be less expensive than traditional utility financing?

A. The difference in cost is a function of the difference in risk investors face. Investor-owned utilities, like APS, traditionally raise the resources necessary to fund their operations through a combination of debt and equity provided by investors. Utility debt and equity investors require that the utility pay a premium for the use of their money which varies based upon the risk the investors perceive they are taking.[86] We call the cost to access this debt and equity the utility's cost of capital. Ratepayer-backed bonds are extraordinarily low risk to investors because repayment of and a return on their investment is secured by a legally enforceable surcharge on customer bills which cannot be changed by the

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[85] Joseph S. Fichera, *Managing Electricity Rates Amidst Increasing Capital Expenditures: Is Securitization the Right Tool? An Update* (National Regulatory Research Institute Jan. 2019), *available at* https://saberpartners.com/wp-content/uploads/2019/01/nrri_securitization_final_fichera.pdf.

[86] APS Witness Ann E. Bulkley explains this relationship at length in her Direct Testimony. *See* Direct Testimony of Ann Bulkley [hereinafter "Bulkley Direct"]. See, in particular, her description of a Bond Yield Plus Risk Premium Analysis at 49:7-17.

Commission, avoided by its customers, or diverted by the utility. Traditional utility debt investment does not enjoy this level of security because it is always dependent upon the utility's ability to pay. While utility equity investment is regarded as one of the lower risk equity investments available, utility equity investors still risk that they will not recover their investment or that they may be disappointed by the return they receive on the investment. Both circumstances result in utility equity investors demanding more of a premium for the use of their funds compared to either ratepayer-backed bonds or utility debt investors.

Q. Has securitization been used within the utility industry?

A. Yes. Securitization has been used within the utility industry for quite a while. Since 1997 there have been a total of 66 securitization transactions undertaken by investor-owned utilities.[87] These occurred in 17 states,[88] including two transactions in Ohio that were filed while I was serving as a Commissioner on the Public Utilities Commission of Ohio.[89]

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[87] Saber Partners, LLC, *List of Investor-Owned Utility Securitization ROC/RRB Bond Transactions 1997-Present*, https://saberpartners.com/list-of-investor-owned-utility-securitization-rocrrb-bond-transactions-1997-present/ (last updated 2019).

[88] *Id*. Transactions occurred in Arkansas, California, Connecticut, Florida, Illinois, Louisiana, Maryland, Massachusetts, Michigan, Montana, New Hampshire, New Jersey, Ohio, Pennsylvania, West Virginia, Wisconsin, and Texas.

[89] *See* Financing Order, Case No. 12-1465-EL-ATS (Pub. Utilities Comm'n of Ohio Oct. 10, 2012), *available at* https://dis.puc.state.oh.us/DocumentRecord.aspx?DocID=286bc283-55c9-45e1-9b6a-2b1469890895 [hereinafter "Ohio Edison Financing Order"]; Financing Order, Case No. 12-1969-EL-ATS (Pub. Utilities Comm'n of Ohio Mar. 20, 2013), *available at* https://dis.puc.state.oh.us/DocumentRecord.aspx?DocID=43a15eee-b18a-4f76-8fb8-4e459e4262ac [hereinafter "Ohio Power Financing Order"].

Q. What were the circumstances of the two transactions in Ohio?

A. Ohio electric distribution utilities were transitioning to retail competition during this timeframe. The legislation guiding the transition authorized the utilities to seek financing orders from the Commission for securitization of previously approved but uncollected deferred regulatory assets associated with the transition. These costs could include fuel, infrastructure, and environmental clean-up expenses. The resulting bonds were called "Phase-In-Recovery Bonds" or "PIR Bonds." Both referenced transactions involved PIR Bonds. The Ohio Commission approved the transactions after finding that they would measurably enhance cost savings to customers and mitigate rate impacts compared to the previously approved recovery methods.[90]

- In the first transaction, which involved First Energy Companies, the Public Utilities Commission of Ohio ("PUCO") granted authorization for $555 million[91] in PIR bonds. The PIR bonds replaced a combination of existing riders which had been granted a rate of return of 6.85 percent.[92] The effective weighted average annual coupon rate and yield of the PIR Bonds was 3.14 percent, which resulted in a nominal cost savings of approximately $106 million.[93]

- For the second transaction, which involved American Electric Power, the PUCO granted authorization for $298 million[94] in PIR bonds with the expectation that the net present value of customer savings would be $28.8

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[90] Ohio Edison Financing Order at 48; Ohio Power Financing Order at 64.
[91] Ohio Edison Financing Order at 5.
[92] Application of Ohio Edison, *et al.* at Exhibit B, Case No. 12-1465-EL-ATS (Pub. Utilities Comm'n of Ohio May 3, 2012), *available at* https://dis.puc.state.oh.us/TiffToPDf/A1001001A12E03B70455J58177.pdf.
[93] Report Regarding Financing Order, Case No. 12-1465-EL-ATS (Pub. Utilities Comm'n of Ohio June 13, 2013), *available at* https://dis.puc.state.oh.us/TiffToPDf/A1001001A13F14B55456H92545.pdf.
[94] Ohio Power Financing Order at 10.

million and the nominal savings would be $22 million.[95] The PIR bonds replaced a regulatory asset that had been recovered through a "Deferred Asset Recovery Rider"[96] at the utility's long-term debt rate, which was then 5.34 percent.[97] Ultimately, the weighted average coupon rate and yield was 3.28 percent, which yielded an estimated net present value savings of $23 million.[98]

Q. Can you offer another example of securitization within the electric utility industry?

A. Yes. The Michigan Public Service Commission authorized Consumers Energy Company to securitize up to $389.6 million for the retirement and demolition of three coal-fired power plants which had a book value of $361.2 million.[99] Consumers Energy Company offered testimony in this case that: (1) it expected the weighted average interest rate for the utility's securitization bonds would be 3.589 percent, which was below the utility's then cost of capital of 9.48 percent;[100] and (2) that removal of the coal plants and associated costs from rate base and replacement of the traditional financing costs with the securitization charges would result in a net present value of savings to customers estimated to be $133.5 million.[101]

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[95] Ohio Power Financing Order at 6.

[96] Application of Ohio Power Company for Authority to Issue Phase-In-Recovery Bonds, Case No. 12-1969-EL-ATS (Pub. Utilities Comm'n of Ohio July 31, 2012), *available at* https://dis.puc.state.oh.us/DocumentRecord.aspx?DocID=0124e09b-fb89-451b-ba8b-67b3acdc6136.

[97] Opinion and Order at 7, Case Nos. 11-351-EL-AIR, 11-352-EL-AIR, et al. (Pub. Utilities Comm'n of Ohio Dec. 14, 2011), *available at* http://dis.puc.state.oh.us/DocumentRecord.aspx?DocID=82e5874e-671b-42bd-9329-58973af696a2.

[98] Issuance Advice Letter For Ohio Power Company's Phase-In-Recovery Bonds at 12, Case No. 12-1969-EL-ATS (Pub. Utilities Comm'n of Ohio July 24, 2013), *available at* https://dis.puc.state.oh.us/DocumentRecord.aspx?DocID=64b17637-56e0-4fbe-bca5-47abface68b9.

[99] Opinion and Order at 62, Case No. U-17473 (Mich. Pub. Serv. Comm'n Dec. 6, 2013), *available at* https://adms.apps.lara.state mi.us/Mpsc/ViewCommissionOrderDocument/10729.

[100] *Id.* at 14.

[101] *Id.* at 15.

Q. Has the Arizona Corporation Commission previously expressed a view regarding securitization?

A. Yes. In the context of approving Electric Competition Rules in 1998, the Commission found that "[s]ecuritization is a financing method that can be utilized to spread stranded costs over a longer period and thus minimize the annual impact."[102]

Q. Have any current Commissioners expressed any interest in securitization?

A. Yes. Chairman Burns issued a letter on March 25, 2020 within the Arizona Corporation Commission Energy Rules Docket expressing his view that a number of standards related to clean energy, energy efficiency, renewable energy, and distributed renewable energy should be adopted. He stated that he anticipated that some fossil fuel energy generators may retire prior to their originally expected closure dates, if these regulations were adopted, although he noted this may occur due to economics regardless. Therefore, he stated that the energy rules "should contain a section regarding securitization and the use of a portion of the money saved with securitization for assisting communities affected by the early closure of these fossil fuel energy generators."[103] Additionally, Chairman Burns issued a second letter in the on-going APS rate case, directing APS to undertake an examination of a variety of accelerated depreciation and securitization options for recovering potentially stranded costs resulting from the earlier than anticipated

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[102] Opinion and Order at 22:15-16, Decision No. 60977 (Ariz. Corp. Comm'n June 22, 1998), *available at* https://docket.images.azcc.gov/0000121160.pdf.
[103] Mar. 25, 2020 Letter from Chairman Burns.

retirement of the Four Corners Generating Plant.[104] Chairman Burns subsequently expanded this request to address potentially stranded costs at the Cholla Generating Station as well.[105]

Q. Are there any downsides to ratepayer-backed securitization for customers?

A. Yes. Once a regulatory asset is securitized, it is outside of the Commission's control and review authority. Because of this, the Commission and stakeholders must be diligent in carefully designing a securitization transaction that will yield the expected benefits. For instance, in the AEP transaction I discussed above, the savings from securitization could and should have been even greater. A post-transaction report found that customers were required to pay at least an additional $3 million in unnecessary interest and fees as a result of poor implementation decisions by the Commission-retained independent financial advisors.[106]Additionally, the professional and investment services required to implement ratepayer-backed bonds properly are an added expense to be considered when evaluating whether a transaction is cost-effective. It is also important to be cognizant of the potential for changing market conditions. For this reason, a finance order must be carefully designed.

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[104] Letter from Chairman Burns, Docket No. E-01345A-19-0236 (Aug. 11, 2020), available at https://docket.images.azcc.gov/E000008353.pdf.

[105] Letter from Chairman Burns, Docket No. E-01345A-19-0236 (Sept. 1, 2020), available at https://docket.images.azcc.gov/E000008707.pdf.

[106] Saber Partners, LLC, *Analysis of Ohio Power Co. Structuring and Pricing of $267,408,000 Ohio Phase-In Recovery Bonds* (prepared for Pub. Utilities Comm'n of Ohio, Case No. 12-1969-EL-ATS Aug. 18, 2013), *available at* https://saberpartners.com/wp-content/uploads/2017/03/Ohio-Power-Pricing-Analysis.pdf.

Q. Are there any other important issues a Commission should consider prior to authorizing ratepayer-backed securitization?

A. Yes. I would also caution that the availability of securitization should not cause a commission or stakeholders to relax their vigilance in evaluating the prudency of utility investments. Before a commission considers a cost that can be recovered through securitization, the utility must clearly establish that it has been prudently incurred and should be recoverable. In the instance of a plant that is no longer a cost-effective resource but has not been fully depreciated, the Commission must first consider the extent to which the remaining plant balance is recoverable. The utility will need to demonstrate that each investment it made in that plant was prudent when it made the investment. For instance, if the utility made an investment when it knew or should have known that the plant would not remain useful throughout the recovery period, the Commission may determine that some or all of the remaining balance will be disallowed. Also, if a plant is not "used and useful" (in a physical or economic sense) then a full or partial disallowance of the plant costs could be appropriate.

Q. How would ratepayer-backed securitization impact investors?

A. Utility investors (either debt or equity) would receive full repayment of the capital they had invested as it is replaced by the proceeds of the ratepayer-backed bonds. Utility investors, however, would not continue to earn any return on this money because it would have been returned to them and would no longer be used by the utility. So long as utilities have adequate access to capital and confidence that their investment will be recoverable, this lost earning opportunity is a disincentive to utilities to seek securitization. Securitization, however, may be appealing to utility investors when the recovery of utility investment is uncertain, such as in the case of stranded assets, or when it provides an opportunity for new investment in replacement resources, where appropriate.

Q. When is securitization useful?

A. Securitization can be a useful tool to reduce customer rate impacts whenever a Commission has authorized the recovery of an expense and the recovery of that expense could be more cost-effectively accomplished through ratepayer-backed bonds. Utilities have sought and commissions have tended to authorize securitization primarily for large, well-defined, non-recurring expenses. This is likely due to the transaction costs involved, the fact that securitization once finalized limits commission oversight, and the lost investment opportunity for utility investors. Utilities have successfully used securitization in times of transition such as when retail competition was adopted in Ohio, as I described above, and when coal-fired generation plants are no longer economic, as I described above in the Michigan example. Other examples include Allegheny Energy, which used ratepayer-backed bonds to finance pollution control upgrades, and Duke Energy, which calculated that it would save its customers $700 million over 20 years when it securitized assets of a closed nuclear plant.[107]

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[107] Uday Varadarajan, David Posner & Jeremy Fisher, *Harnessing Financial Tools to Transform the Electric Sector* 13 (Sierra Club Nov. 2018), *available at* https://www.sierraclub.org/sites/www.sierraclub.org/files/sierra-club-harnessing-financial-tools-electric-sector.pdf.

Q. How is securitization relevant to this matter?

A. The Commission establishes a revenue requirement based in large measure upon the utility's cost of capital during a rate case such as this one. It is an opportune moment to evaluate whether portions of the utility's capital need could be more cost-effectively managed through ratepayer-funded bonds. In this matter, I see at least three opportunities to consider ratepayer-backed bonds as a tool to improve customer outcomes. APS has suggested extending the cost recovery time for deferred expenses related to the Four Corners SCRs and the Ocotillo Modernization Project amortization schedules in order to mitigate bill impacts to customers.[108] The SCR deferral is $33.2 million.[109] The deferral at December 31, 2020 for the Ocotillo Modernization Project is $62 million.[110] APS also proposes to extend recovery time for the Cholla Unit 2 regulatory asset amortization.[111] If the Commission agrees that APS should recover these deferrals, then instead of extending the cost recovery—which lowers customers impacts in the near term but increases overall costs—the Commission could consider whether these should be funded by ratepayer-backed securities which could lower customers' overall costs and still mitigate rate impacts.

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[108] Ariz. Pub. Serv. Application at 18, Docket No. E-01345A-19-0236 (Oct. 31, 2019), *available at* https://docket.images.azcc.gov/E000003517.pdf.
[109] Blankenship Direct at 36:19-20.
[110] *Id.* at 35:1-4.
[111] *Id.* at 41:4-9.

Q. What cost of capital has APS assumed inside of this rate case?

A. APS Company Witness Blankenship has testified that the Company is requesting an adjusted weighted average cost of capital of 7.41 percent.[112]

Q. What interest rate would you expect to be available for a ratepayer-backed bond?

A. Because of the low risk of these bonds, I would consider the risk-free rate as a relevant point of reference. APS Witness Bulkley has testified that she considers an appropriate reference for the risk-free rate to be the projected yields on 30-year U.S. Treasury bonds.[113] On July 24, 2020, this rate was 1.23 percent.[114] As an additional point of reference, on July 16, 2020, the 30-year-fixed mortgage rate fell below 3 percent.[115] While perhaps ratepayer-backed bonds would be viewed as slightly more risky than U.S. Treasury Bonds, they are certainly less risky than an individual home mortgage. Based on these data points, I would anticipate that ratepayer-backed bonds would be available at somewhere between 1.23 percent and 3 percent.

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[112] *Id.* at 12:24-25.
[113] Bulkley Direct at 45:8-9.
[114] U.S. Dep't of Treas., *Daily Treasury Yield Curve Rates*, https://www.treasury.gov/resource-center/data-chart-center/interest-rates/pages/TextView.aspx?data=yieldYear&year=2020 (last visited Sept. 16, 2020).
[115] Kathy Orton, *30-year fixed mortgage rate falls below 3 percent to lowest level in history,* THE WASHINGTON POST, July 16, 2020, *available at* https://www.washingtonpost.com/business/2020/07/16/30-year-fixed-mortgage-rate-falls-below-3-percent/.

Q. What is the significance of the APS requested cost of capital and the cost of a ratepayer-backed bond?

A. I refer to this range to illustrate that the Commission could conservatively expect that ratepayer-backed bonds could reduce the cost of capital by over half, offering customers a substantial savings opportunity.

Q. Are there any other circumstances that have come to light in this matter for which ratepayer-back bonds may be an appropriate tool?

A. Yes. Concurrent with my testimony, Tyler Comings filed testimony on behalf of the Sierra Club finding that APS would enjoy substantial savings if it were to retire Four Corners Units 4 and 5 in 2023 instead of 2031. Early retirement could create just the type of stranded assets for which securitization may be appealing to utility investors. As I described above, Michigan consumers enjoyed substantial savings when the Michigan Public Service Commission authorized ratepayer-backed bonds to finance expenses related to the closure of three coal-fired plants. Securitization may be a useful tool here in implementing an earlier-than-anticipated retirement of Four Corners Units 4 and 5. This use is also consistent with the suggestion made by Chairman Burns within the Energy Rules docket.[116]

Q. What design features could be incorporated into a financing order authorizing securitization to ensure the securitization achieves customer benefits?

A. A commission adopting a finance order to authorize securitization could consider the following design features to ensure that the transaction achieves the intended benefits:

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[116] Mar. 25, 2020 Letter from Chairman Burns.

- The commission retains authority to approve the investment banking firm managing the offering.
- The commission retains bond counsel and/or other an independent advisor to oversee the transaction and to advise the commission.
- Consumer savings and rate impacts are documented.
- Proceeds of the ratepayer-backed bonds may be used only to replaced existing capital (including the cost of the bonds), not to undertake new debt.
- Savings from securitization should be passed along to customers directly or indirectly as a public benefit through funding of costs required to assure a just transition during the early retirement of an asset, including but not limited to severance pay and job training expenses for affected employees.
- Bonds must be competitively marketed as opposed to sold through private negotiation.
- Financing costs and weighted average interest of the bonds are capped at levels to assure the expected benefits.
- Expected benefits should assure substantial, tangible, quantifiable net present value benefits, greater than without bonds, maximizing the net present value savings.
- The commission retains authority to approve the bond structuring and pricing.

Q. What are your recommendations with regard to securitization?

A. The Commission should consider retaining a qualified expert to conduct an independent evaluation to determine whether there are large, well-defined, non-recurring expenses on the utility's balance sheet that could cost-effectively be funded by ratepayer-backed bonds. I also recommend that the Commission consider the tool of securitization when evaluating the opportunities to close fossil fuel generation units that have become or soon will be non-economic.

Q. Does this conclude your testimony?

A. Yes, it does.

Attachment CR-1

Resume of Cheryl Roberto

Cheryl Roberto, Senior Principal

Synapse Energy Economics I 485 Massachusetts Avenue, Suite 3 I Cambridge, MA 02139
croberto@synapse-energy.com

PROFESSIONAL EXPERIENCE

Synapse Energy Economics Inc., Cambridge, MA. *Senior Principal*, 2019–present.

Provides expert consulting services for removing operational, regulatory, and policy barriers to the decarbonization of the energy system on behalf of mission-driven investors, regulators, and other stakeholders seeking to accelerate the transformation of the grid.

Twenty First Century Utilities, Washington, D.C. *Senior Advisor*, 2019 – present; *Managing Director: Utility Transformation,* 2015–2019.

Worked to transform, through acquisition and operation, regulated utilities with a 21st century model that drives mass adoption of clean, low-cost energy producing and energy saving technologies. Advanced utility of the future policies, operations, technologies, and governance inclusive of grid optimization, de-carbonization of utility-scale fleet, implementation of TFC Utilities' Million Rate Base Market Platform, and achieving sustainable business value.

Environmental Defense Fund, *Associate Vice President, EDF Clean Energy Program,* 2013–2015.

Led national program advocating regulatory reform to help modernize U.S. energy infrastructure, accelerate deployment of clean technologies into the nation's electric system, and break down the regulatory and financial barriers to broad-scale adoption of renewable energy, energy efficiency, and other innovative ways to generate, distribute, and use energy. Managed a team of over 30 individuals and an annual budget of $11 million dollars.

Public Utilities Commission of Ohio, Columbus, Ohio. *Commissioner,* 2008–2012.

In addition to customary responsibilities of a Commissioner, initiated a national pilot partnership with the United States Department of Energy (U.S. DOE) for combined heat power; served as Co-Chair 2012 National Electricity Forum, Co-Chair, State and Local Energy Efficiency Action Network Driving Ratepayer-Funded Efficiency Working Group (also Chair Sub-Committee for Utility Financial Incentives), Co-Leader U.S. Agency for International Development (U.S. A.I.D.)/NARUC meeting with National Electricity Regulatory Commission of Ukraine (Kiev, Ukraine, September 2011), and a member of the National Association of Regulatory Utility Commissioners (NARUC):

- Task Force on Environmental Regulation and Generation (2012)
- Committee on Critical Infrastructure (also served as Vice Chair) (2010–2012)
- Committee on Electricity (2008–2012)

Department of Public Utilities, City of Columbus, Columbus, OH. *Director*, 2003–2006, *Deputy Director for Operations,* 2001–2003.

Led municipal water, wastewater, and electric utility with annual operating budget of $400 million dollars, an annual capital budget of $250 million dollars, and a staff of 1300 people serving the nation's 15th largest city and 22 Central Ohio political subdivisions. Established and successfully managed $2.5 billion dollar capital engineering and construction program, the largest ever undertaken by the City of Columbus. Completed extensive restructuring of utility rate models and design for the first time in two decades to validate cost of service. Managed successful water quality-focused environmental initiatives involving extensive stakeholder outreach and public education, including the development and adoption of the Hellbranch Run Watershed protection Overlay and Clean Water Act Facilities Plan.

Office of the Mayor, City of Columbus, Ohio, Columbus, OH. *Policy Advisor*, 2000.

Provided advice on public policy issues including health, environment, public utilities, housing, public safety, and development to support the launch of the Mayoral administration of Michael B. Coleman.

Office of the City Attorney, City of Columbus, Columbus, OH. *Assistant City Attorney,* 1997–2000.

Represented City of Columbus for municipal law issues related to environmental, health, and safety matters including environmental permitting (NPDES, Title V, MS4), regulatory enforcement (industrial pretreatment, fire code, storm water development), compliance counseling (RCRA, OSHA, Clean Drinking Water), environmental liability management (PCB disposal, real estate), and contracts.

Commonwealth of Pennsylvania, *Assistant Counsel, Office of Chief Counsel,* 1996–1997.

Served as counsel to the Department of Environmental Protection concerning Superfund, drinking water, wastewater, solid and hazardous waste, and air pollution.

Cheryl L. Roberto, Esq. *Owner,* 1993–1996.

Built boutique law practice specializing in environmental matters; representative clients included City of Erie, Pennsylvania, Erie Sewer Authority, and Erie County Department of Health.

State of Ohio, Columbus, OH. *Assistant Attorney General,* 1987–1992.

Represented the State of Ohio in Environmental and Consumer Protection matters through administrative proceedings, civil actions, and criminal prosecutions concerning wastewater, solid and hazardous waste, and air pollution.

EDUCATION

Moritz College of Law, The Ohio State University, Columbus, OH
Juris Doctor, 1987. Member, Journal of Dispute Resolution. Recipient, University Scholarship and Caris Fellowship. Founding Member, Board of Directors for the Student Funded Fellowship.

Kent State University, Kent, OH
BA, Political Science, *cum laude*, 1984.

Graduated with General Honors from the Honors College. Omicron Delta Kappa and Pi Sigma Alpha. Recipient of Manchester Cup, Junior Service Award, Sophomore Leadership Award, Honor's Scholarship. Honor's Dissertation adopted and implemented by K.S.U. Board of Trustees: "Student Leadership Compensation Model for Kent State University," KSU Library Archives, Honors Papers (1984).

CONTINUING EDUCATION

Harvard University, John F. Kennedy School of Government, Cambridge, MA
Executive Education Certificate of Completion: Strategic Management of Regulatory and Enforcement Agencies, 2012.

University of Colorado, Silicon Flatirons Center, Boulder, CO
Institute for Regulatory Law and Economics, Seminar, May 2012.

Scott Hempling Attorney at Law LLC, Electricity Law Update Seminar, March 2012.

American Law Institute/American Bar Association
42nd Annual Advanced Course of Study in Environmental Law, February 2012.

SNL Center for Financial Education, Essentials of Regulatory Finance, June 2011.

National Regulatory Research Institute, Electricity's Current Challenges: Capital Investment, Renewables, Energy Efficiency, "Modern" IRP, and Transmission. January 2011.

Michigan State University, East Lansing, MI
Advanced Regulatory Studies Program, "Ratemaking, Accounting, and Economics," September 2010.

HONORS AND AWARDS

Inspiring Efficiency Leadership Award, January 2013.
Presented by the Midwest Energy Efficiency Alliance to the organization or individual in the 13-state region who has served as a strong leader in support of energy efficiency in their city, state, region, company, or community.

BOARDS AND COMMISIONS

- Executive Group for the State and Local Energy Efficiency Network (2012–present)
- Board of Directors of the National Regulatory Research Institute (NRRI) (2012)
- Financial Research Institute (FRI) Advisory Board (2011–2012), Chair, Hot Topic Hotline Committee (2012)
- Audubon Ohio, Board Member (2007–2008)
- Franklin County Planning Commission, Member (2001–2006)

- Solid Waste Authority of Central Ohio, Board Member (2003–2006); Engineering, Operations and Compliance Committee Chair
- Mid-Ohio Regional Planning Commission, Member (2003–2006); Greenways Steering Committee Chair; Member Public Works Integrating Committee
- Community Research Partners, Board Member (2000–2002)

PRESENTATIONS

Roberto, C. 2017. "Aligning Economic Incentives: Evolution of the Utility Business Model." Hawaii Clean Energy Law and Finance. Honolulu, HI. July 21, 2017.

Roberto, C. 2017. "TFC's Million Rate Base Model." National Association of Regulatory Utility Commissioners Committee on Energy Resources and the Environment. May 15, 2017.

Roberto, C. 2017. "Creating a Resilient Energy Economy." Maui Energy Conference. Maui, HI. April 6, 2017.

Roberto, C. 2016. "A Twenty First Century Utility." Department of Energy Quadrennial Energy Review Second Installment Public Meeting. Atlanta, GA. May 24, 2016.

Roberto, C. 2016. "What is Sustainable Electricity." Electric Power Research Institute ENV-VISION: Environmental Vision – An International Electricity Sector Conference. Washington, D.C. May 10, 2016.

Roberto, C. 2016. "Utility Transformation: Opportunities for Jobs, our Communities & the Planet." Florida Women in Energy Conference. April 15, 2016.

Roberto, C. 2016. "Confluence of Environmental & Economic Regulation." Ohio Bar Association Environmental Law Conference. Columbus, OH. April 14, 2016.

Roberto, C. 2016. "Can Ohio Meet the Clean Power Plan?" John Glenn College of Public Affairs Dialogue. January 21, 2016.

Roberto, C. 2015. "Right to Data Access." SmartGrid Consumer Collaborative. August 26, 2015.

Roberto, C. 2015. "Success Factors: Career Profiles of Women Leaders." National Association for Environmental Management Women's EHS & Sustainability Leadership Roundtable. San Antonio, TX. April 16, 2015.

Roberto, C. 2015. "Smart Grid: Lessons Learned." Energy Thought Summit 2015. Austin, TX. March 25, 2015.

Roberto, C. 2015. "Decarbonizing the Energy Supply." Energy & Climate Change: 15th National Conference and Global Forum on Science, Policy, and the Environment. January 27, 2015.

Roberto, C. 2014. "Clean Energy Policy -- Looking Ahead to 2020." Forum 20/20: Innovation and the Future of CleanTech. October 29, 2014.

Roberto, C. 2014. "2014 EPRI-TVA Environmental Benchmarking Forum, Charlotte, NC, October 6, 2014.

Roberto, C. 2014. "Product Innovations for Retail Customers." Retail Energy Supply Association's 2014 Energy Competition Symposium. Columbus, Ohio. October 2, 2014.

Roberto, C. 2013. "Policies Matter: Practical Approaches for Regulators to Encourage CHP." WVU Law Center for Energy & Sustainable Development Energy Conference 2013. April 24, 2013.

Roberto, C. 2013. "Enhancing Industry through Industrial Energy Efficiency & Combined Heat and Power." National Governors Association Policy Academy. March 4, 2013.

Roberto, C. 2013. "Breaking Through the 'Grid'-lock." ARPA-E Energy Innovation Summit. February 26, 2013.

Roberto, C. 2013. "Investing in Combined Heat and Power: Benefits and Challenges." National Association of Regulatory Utility Commissioners Winter Meeting. February 5, 2013.

Roberto, C. 2013. "Should There Be a Change to Cost Effectiveness Testing?" 2013 Midwest Energy Solutions Conference. January 17, 2013.

Roberto, C. 2013. "Working Together to Advance Energy Efficiency: Partnerships for Tackling Persistent Barriers & Achieving Results." Department of Energy. January 16, 2013.

Roberto, C. 2013. "Transmission Cost Allocation: What Lies Ahead?" Harvard Electricity Policy Group Sixty-Eighth Plenary Session. October 11-12, 2012.

Roberto, C. 2012. "What is the future design of the regulatory process?" 2012 Financial Research Institute Symposium: Emerging Issues in the Management of the Regulatory Interface, September 19, 2012.

Roberto, C. 2012. NARUC/FERC Forum on Reliability and the Environment. February 7, 2012.

Roberto, C. 2012. "Testing…Testing: Are We Getting the Most Value out of Cost-Effectiveness Tests for Energy Efficiency?" Mid-Atlantic Conference of Regulatory Utilities Commissioners 17th Annual Education Conference. June 26, 2012.

Roberto, C. 2012. "Successful Approaches to Promote Industrial EE and CHP." U.S. DOE Midwest Industrial Energy Efficiency and Combined Heat & Power Dialogue Meeting. June 21, 2012.

Roberto, C. 2012. "Promoting Industrial CHP Through Utility Ownership." Industrial Energy Efficiency and CHP Dialogue DOE Regional Meeting—Midwest. June 22, 2012.

Roberto, C. 2012. "All Cost-Effective Energy Efficiency. All? You're Kidding, Aren't You." Financial Research Institute, Hot Topic Webinar. June 13, 2012.

Roberto, C. 2012. "Natural Gas Pipeline Safety: How to Address Cost-Effectiveness and Ratemaking Concerns While Ensuring Public Safety." National Regulatory Research Institute Teleseminar, original broadcast. April 26, 2012.

Roberto, C. 2012. "Using Regulations and Markets to Broaden and Deepen the Savings Delivered by Energy Providers" Policies for Energy Provider Delivery of Energy Efficiency North American Regional Policy Dialogue. Washington, D.C. April 18-19, 2012.

Roberto, C. 2011. "Pipeline Safety—Steps to a Robust Integrity Management Program." Financial Research Institute, Hot Topic Webinar. December 15, 2011.

Roberto, C. 2011. "Safety First! How Pipeline Safety Programs are Evolving." 2011 NARUC Annual Meeting.

Roberto, C. 2011. "What is a 'Utility' Anyway and Who Needs It?" National Regulatory Research Institute Teleseminar - original broadcast. February 2, 2011.

Roberto, C. 2011. "A Black Swan? Geomagnetic Storms, Pandemics & Cyber Events: Planning for the Uncertain." 2011 NARUC Winter Committee Meetings, Committees on Electricity and Critical Infrastructure.

Roberto, C. 2011. "CyberSHIELD: Cybersecurity Legislation and the SHIELD Act." 2011 NARUC Summer Committee Meetings, Committees on Consumer Affairs and Critical Infrastructure.

Roberto, C. 2011. "Regulatory Tools and Limits." Serving National Security Workshop. July 20, 2011.

Roberto, C. 2011. "Regulation, Accounting & the Capital Markets" 2011 Financial Research Institute Symposium, The Search for Capital: Utility Financing in the 21st Century. September 2011.

Roberto, C. 2001. "Hellbranch Run Enhanced Development Standards: The process to develop the City of Columbus draft Hellbranch Run Watershed Protection Ordinance." Water Management Association of Ohio, 2001 Fall Conference.

TESTIMONY

United States Senate Committee on Energy and Natural Resources (SD-366): Direct testimony of Cheryl Roberto regarding national electric grid modernization, reliability, and security. April 10, 2014.

Roberto, C., N. Dormady. 2013. *The Costs of Inefficiency: Ignoring Ohio's Energy Efficiency Potential.* John Glenn School of Public Affairs.

Federal Energy Regulatory Commission Reliability Technical Conference (Docket No. AD12-1-000): Direct testimony of Cheryl Roberto regarding maintaining electric grid reliability and affordability while meeting EPA goals. On behalf of the Public Utilities Commission of Ohio. November 30, 2011.

PUBLICATIONS

Biewald, B., D. Glick, J. Hall, C. Odom, C. Roberto, R. Wilson. 2020. *Investing In Failure: How Large Power Companies are Undermining their Decarbonization Targets.* Synapse Energy Economics for Climate Majority Project.

Glick, D, D. Bhandari, C. Roberto, T. Woolf. 2020. *Review of benefit-cost analysis for the EPA's proposed revisions to the 2015 Steam Electric Effluent Limitations Guidelines.* Synapse Energy Economics for Earthjustice and Environmental Integrity Project.

Whited, M., C. Roberto. 2019. *Multi-Year Rate Plans: Core Elements and Case Studies.* Synapse Energy Economics for Maryland PC51 and Case 9618.

Roberto, C. 1987. *Limits of Judicial Authority in Pretrial Settlement Under Rule 16 of the Federal Rules of Civil Procedure.* 2 Ohio St. J. Dis. Res. 311.

Roberto, C. 1987. *Alternative Dispute Resolution: A Resource for Practitioners.* Ohio Lawyer Practitioner's Desk-top Reference.

Resume updated March 2020

Attachment CR-2

Leveraging Advanced Metering Infrastructure to Save Energy

Leveraging Advanced Metering Infrastructure To Save Energy

Rachel Gold, Corri Waters, and Dan York

January 3, 2020. Revised January 27, 2020.
Report U2001

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Revision

The original edition of this report did not include all six use cases for Southern California Edison; the utility initially reported only one use case (TOU rates) in the survey. SCE subsequently provided data clarifying how it uses AMI in support of the other five use cases. We have updated table 1 to reflect this change.

About the Authors

Rachel Gold leads ACEEE's Utilities Program. Her research focuses on energy efficiency programs and policy and on utility regulation and ratemaking. She also provides technical assistance to utilities, state regulators, and efficiency program administrators. Rachel was previously in the electricity practice at Rocky Mountain Institute and on the regulatory affairs and market development team at Opower. She holds a master of public policy from the University of California, Berkeley, and a bachelor of science in biology and environmental studies from Brandeis University.

Corri Waters was a research assistant for ACEEE's Utilities Program. She supported the *Utility Scorecard* and conducted research on energy efficiency program design and cost effectiveness. Prior to joining ACEEE, Corri interned at the Maryland Clean Energy Center and served as the project manager for Pittsburgh's Black Environmental Collective. She earned a bachelor of science in mathematics with a minor in environmental and sustainability studies from Loyola University Maryland in 2018.

Dan York is an ACEEE senior fellow engaged primarily in utilities and local policy research and technical assistance. He focuses on tracking and analyzing trends and emerging issues in utility-sector energy efficiency programs. Dan has a bachelor's degree in mechanical engineering from the University of Minnesota. His master of science and PhD degrees, from the University of Wisconsin–Madison, are both in land resources with an emphasis on energy analysis and policy.

Acknowledgments

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Executive Summary

KEY TAKEAWAYS

- Advanced metering infrastructure (AMI) has grown rapidly and is in place in many states, covering nearly half of all meters in the United States. It is a key element of grid modernization.
- Providing customers with AMI data alone generally does not result in energy savings. AMI data need to be paired with customer engagement tools; pricing strategies; and programs with incentives and services that enable, motivate, and support customers to take actions and make changes to modify their energy use.
- Utilities are largely missing the opportunity to utilize AMI data to improve their energy efficiency and demand response offerings, in part due to regulatory, administrative, and technological barriers.
- Opportunities for leveraging AMI for energy savings include time-varying pricing (TVR); more granular energy usage feedback, including time and locational value; customer targeting and technical assistance; programs that align payment with metered performance; and more actionable insights from evaluation, measurement, and verification.
- Utilities can leverage AMI to support energy efficiency by investing in complementary systems and workforce, prioritizing the customer experience, and piloting new approaches and ways of leveraging AMI data.
- Regulators can encourage utilities to better leverage AMI by quantifying and incorporating benefits from saving energy in the AMI business cases in regulatory proposals, then adjusting shareholder compensation based on performance in realizing those benefits. They can also establish clear and reasonable protocols for data access, set performance standards for metered energy savings, and encourage innovation and pilots that could leverage AMI but might involve technology or business model risk.

BENEFITS OF ADVANCED METERING INFRASTRUCTURE

Advanced metering infrastructure (AMI) consists of meters, communications networks, and data management systems that collect, transmit, and record electricity consumption data in daily or shorter intervals. AMI is considered a foundational element of electric grid modernization by many within the electric utility industry. More timely and more granular data can be used to influence customer behavior and energy consumption when used in ways that engage, motivate, and reward customers. For utilities and grid operators, AMI provides a variety of operational benefits, including reduced costs for metering and billing, faster responses to outages, and improved safety.[1] The operational benefits of AMI compared with traditional manual metering have typically been the primary rationale used

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[1] See US Department of Energy, *Advanced Metering Infrastructure and Customer Systems: Results from the Smart Grid Investment Grant Program* (Washington, DC: DOE, 2016), www.energy.gov/sites/prod/files/2016/12/f34/AMI%20Summary%20Report_09-26-16.pdf.

by utilities and regulators to invest in these systems.[2] The capabilities of AMI as an information resource and tool for customers to reduce their costs and achieve other benefits generally have been underutilized, as indicated by our utility surveys and interviews with industry experts.

Moreover, to the extent that AMI has been considered a means of influencing customer energy use, it has most often been viewed as a tool for affecting the timing of energy usage (e.g., for load shifting and demand response). Nevertheless, there are important ways that AMI can enable and support customer energy efficiency savings via several use cases. These strategic uses include:

- Enhancing the quality of insights on energy use from near-real-time feedback
- Providing time-varying pricing that reflects fluctuating energy costs at different times of day and year. Near-real-time feedback, combined with communications and possible automation, can better inform and motivate customers to respond to pricing signals and change their energy use accordingly.
- Targeting customers for programs best suited to their energy use profiles
- Promoting grid-interactive efficient buildings that extract more grid value from customer programs by providing more flexible demand[3]
- Supporting energy procurement and meter-based pay-for-performance (P4P)[4]
- Producing granular data needed for advanced measurement and verification of customer energy and demand savings (M&V 2.0.)
- Enabling conservation voltage reduction (CVR) on electricity distribution networks to reduce demand and energy use

This report places a special focus on the potential application of AMI tools to realize customer energy efficiency. Another potential benefit is use of AMI data for utility system planning, particularly for distribution systems. However we found no significant examples of the impacts of this use case on energy efficiency in our research.

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[2] Traditional metering is based on meters that are read manually, usually at monthly intervals. The data must be entered or uploaded to utility records and billing systems; they cannot be transmitted automatically via the various communications technologies employed with AMI.

[3] Grid-interactive efficient buildings (GEBs) are grid-connected buildings with information, controls, and communications technologies able to respond to signals from the grid to modify energy demand.

[4] P4P rewards energy savings on an ongoing basis as the savings occur, rather than providing up-front payments based on deemed or custom measure calculations. Meter-based P4P programs determine performance payments according to savings quantified using meter data, including daily or hourly data from AMI where available. See C. Best, M. Fisher, and M. Wyman, "Case Study: Policy Pathways to Meter-Based Pay-for-Performance in CA, NY, and OR," *Recurve*, September 3, 2019, www.recurve.com/blog/policy-pathways-to-meter-based-pay-for-performance.

POTENTIAL ENERGY SAVINGS FROM AMI-LEVERAGED ENERGY EFFICIENCY

The energy savings possible through different uses of AMI to advance energy efficiency vary. The results for some applications have been well documented; these include (as percentages of total annual electricity use in kilowatt-hours):

- Near-real-time and behavioral feedback: 1–8%[5]
- Pricing with time-varying rates: 1–7%
- Conservation voltage reduction: 1–4%

Other uses of AMI have a high potential to improve energy efficiency programs and evaluation, thereby contributing to and supporting customer savings. For example, in program design AMI data can be used for customer targeting and recruitment. In program evaluation, AMI can provide accurate and timely data to facilitate P4P approaches as well as allow rapid feedback to management for program improvement.

PRACTICES TO LEVERAGE AMI TO SAVE ENERGY

Leveraging AMI to save energy requires active efforts from utilities in their roles as energy efficiency program administrators, grid planners, and grid operators. Utilities are also the primary entities identifying AMI technologies, selecting vendors, and investing in these resources on behalf of the system and their shareholders. Utilities need the support of regulators and stakeholders to implement AMI in a manner that optimizes customer as well as operational benefits.

Utilities and program administrators need to break down traditional internal business and operations silos to manage and use AMI to its fullest capabilities to benefit customers and system operations. Utility and regulatory practices that support robust AMI utilization include:

- Crafting effective communications that inform, engage, and motivate customers
- Quantifying and incorporating benefits from energy savings in business cases
- Adjusting shareholder compensation for AMI based on performance in delivering customer benefits from AMI investments
- Setting clear and reasonable performance standards for data access and energy savings
- Encouraging innovation and pilots that leverage AMI, including innovative rate designs, new means of delivering energy use feedback, and new program design tools that use AMI data, such as P4P and targeting.

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[5] Feedback devices and programs show wide variation due to different designs such as opt-in versus opt-out. See R. Sussman and M. Chikumbo, *Behavior Change Programs: Status and Impact* (Washington, DC: ACEEE, 2016), www.aceee.org/research-report/b1601.

CONCLUSIONS

We find that many utilities are underexploiting AMI capabilities and attendant benefits, thus missing a key tool to deliver value to their customers and systems. This is due in part to organizational barriers including silos and workforce challenges, data access and sharing issues, and difficulties communicating the benefits and costs of AMI to key stakeholders. AMI data can help utilities and third parties create better, more compelling, more cost-effective demand-side offerings. AMI also can enable energy efficiency to expand its role as a grid resource by providing temporal and locational value of energy savings in highly granular form. Utilities can learn from the experiences of other utilities that have been successful in rolling out AMI and associated pricing and customer programs. They must actively engage their customers and offer them a range of services to support their energy-saving investments and actions. AMI itself is just a tool that can enable energy markets to support energy efficiency and clean energy goals. When used effectively by utilities or third-party service providers, AMI can improve grid performance, save energy, and reduce customer bills.

Introduction

Advanced metering infrastructure (AMI) has increased the availability of more granular and more readily available data on customers' electricity usage. Traditionally, consumption information was available at best on a monthly basis, with a one-way flow of data from the customer to the utility. Now, with more granular information and relevant insights about their energy usage, customers can become active participants in lowering their own bills; improving their health, productivity, and comfort; and providing value back to other participants on the grid. These data are a critical building block of a more active marketplace for demand-side resources in which customers, working with or through third parties and utilities, support the integration of renewables into the grid, foster reliability, and build resilience (Relf, York, and Kushler 2018).

Interval data can come from multiple sources, including AMI, communicating smart thermostats, customer submetering devices and sensors, and other advanced metering functionality (AMF). AMI is the most prevalent source of interval data about customers' electricity use. It consists of meters that collect electricity consumption data in daily or smaller intervals, as well as the communications networks and data management systems to transmit, store, and process the data. AMI has expanded to more than half of all meters in the United States and is projected to reach 90 million units, or close to 60% of all meters, by 2020 (Cooper 2017).[1]

Current technology and policy trends have made AMI increasingly important. Decreases in the cost of renewables and distributed energy resources (DER), along with policy efforts supporting decarbonization, are boosting the value of flexible demand-side resources and hastening their deployment. To take advantage of this opportunity, utilities, markets, and customers require good information about what services demand-side resources can provide. Utilities need more granular load forecasts to support high-quality distribution and integrated resource planning that better anticipates grid needs. They also need customers to be able to see and respond to variation in the cost of delivering energy throughout the day and year, which requires time- and eventually location-based pricing or valuation.

AMI rollouts, sometimes included as a part of smart grid or grid modernization plans, tend to highlight operational benefits to utilities. However many also cite potential customer benefits, including bill and outage management and opportunities, through their actions, to save energy via efficiency and demand response. For example, in the smart grid business cases arising out of the American Recovery and Reinvestment Act of 2009 (ARRA), many utilities cited potential energy efficiency and peak demand benefits such as savings from feedback, time-varying rates, and actions taken through customer interaction with in-home devices (DOE 2019).

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[1] EIA data for 2018 on AMI penetration show that penetration rates among residential and commercial customers closely track total penetration rates (EIA 2019a). AMI penetration rates for industrial customers show wider divergence from total penetration, likely a reflection of more-specialized needs and arrangements with their utilities.

In the years since ARRA, some efficiency program administrators have been finding it increasingly challenging to maintain cost-effective portfolios in the face of sustained decreases in average avoided costs as well as rising appliance and equipment standard baselines. With the rise in availability of more-advanced data analytics, utilities and implementers can use lessons learned from online and retail sales and advertising to more effectively target customers for energy efficiency opportunities based on not just demographics but also their interval usage. Such targeting and data analytics have the potential to increase savings and boost cost effectiveness (Borgeson and Gerke 2018).

Despite AMI's potential value to save energy, most discussion of its value focuses on operational benefits, and our research suggests that the value of AMI for customer energy efficiency programs and market enablement is underexploited. This creates two forms of potential risk for utilities. First, utilities with AMI that are held accountable for customer benefits and do not deliver may risk regulators' denying cost recovery for existing investments. Second, for those utilities without AMI, or for those that seek to invest further in grid modernization, the industry's poor performance in delivering customer benefits (or articulating how they will do so) may undermine these utilities' ability to gain approval for these large future infrastructure investments.[2] Recent rejections in Massachusetts, Kentucky, Virginia, and New Mexico are cases in point; the New Mexico rejection specifically noted that the AMI proposal from PNM (Public Service Company of New Mexico) failed to "take advantage of possible energy efficiency measures, identify sufficient operational benefits, or provide meaningful opt-out opportunities" (Massachusetts DPU 2018; Kentucky PSC 2018; New Mexico PRC 2018; Virginia Electric and Power Company 2019).

This report seeks to shed light on the ways utilities, program administrators, and third-party service providers are using AMI data in support of customer energy efficiency.[3] We begin by outlining the operational and customer benefits of AMI to identify the use cases for AMI to advance energy efficiency. We examine how and to what extent AMI data are currently used to drive energy savings in a variety of use cases. For promising use cases that are underexploited, we identify barriers to using these data in support of energy efficiency and discuss options to address those barriers from leading examples. Finally, using lessons learned from these leading utilities and market actors, we close by providing

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[2] US grid investment grew by 8% in 2018, with 60% of spending in the distribution grid, and analysts project continued growth in transmission and distribution to replace aging infrastructure, support renewables integration, and provide a source of growth for utilities with more limited capital investment opportunities due to flat load growth (IEA 2019; DOE 2015).

[3] This report addresses two primary types of customer action to modify energy use in order to reduce costs. *Energy efficiency* signifies measures and technologies implemented by customers that reduce the amount of energy used whenever a given device is operated. *Demand response* encompasses various customer actions taken to reduce or shift electric load in response to signals or requests from a utility or system operator. This typically is done to provide load relief at a time of high system demand. Demand response measures primarily shift loads and do not necessarily reduce energy use. Some savings may occur. However energy efficiency by definition always reduces energy use for a given application.

recommendations for regulators and utilities seeking to leverage interval data and communications technologies as a tool to enable all cost-effective energy efficiency.

Research Objectives and Methodology

The primary goal of this research is to show how utilities with AMI can better leverage its capabilities to increase energy efficiency program effectiveness, influence customer behavior to reduce energy use, support more robust energy efficiency markets, and deliver system benefits through energy efficiency. We set out to answer the following research questions:

- How do smart grid businesses characterize the energy savings case for AMI?
- Is there evidence that AMI deployment has saved energy or reduced peak demand?
- What missing opportunities are available to better leverage AMI data for energy savings? Could they use AMF technologies other than AMI?
- What are the barriers to better leveraging AMI data to save energy?
- What supportive investments and programs are needed to fully realize energy savings benefits from AMI?
- What rules can regulators adopt to help customers realize greater energy savings?

To answer these questions, we reviewed existing research and experience on AMI rollouts. Industry experts, including former regulatory staff and contacts from national labs, the US Department of Energy (DOE), and utilities, provided input on the history and current status of AMI, including barriers to and drivers of adoption. Through these resources we identified the range of AMI technologies and their potential implications for energy efficiency and customer benefits.

To characterize the current landscape of how utilities are leveraging AMI, ACEEE conducted a survey of the top 52 electric utilities by sales, the results of which are reported throughout this report. The data from this survey are also being used for ACEEE's forthcoming 2020 *Utility Scorecard*. Where information was available, we captured which utilities had the following programs or program measures in 2018:

- Real-time energy use feedback to customers
- Behavior-based programs with customer feedback and insights
- Time-of-use rates
- Program targeting, marketing, and technical assistance using insights from data disaggregation
- Grid-interactive efficient buildings[4]
- Conservation voltage reduction or volt/VAR optimization

[4] Grid-interactive efficient buildings are energy-efficient buildings with smart technologies characterized by the active use of DERs to optimize energy use for grid services, occupant needs and preferences, and cost reductions in a continuous and integrated way (Neukomm et al. 2019).

We identified seven potential use cases of AMI. In addition to the list above, our literature review and interviews identified additional use cases: more real-time, iterative measurement and verification (M&V), and performance-based procurement of energy, capacity, and grid services.

To assess whether these AMI use cases can lead to energy savings, we built on our initial literature review, examining publicly available demand-side management program filings and case studies from the literature on AMI for examples of these use cases. We conducted structured interviews with nine program administrators or implementers to understand program details and structures and to identify lessons learned and challenges faced.

Advanced Metering Infrastructure and Advanced Metering Functionality

The Energy Information Administration defines AMI this way:

> Meters that have the capability to measure and record usage data at hourly or shorter intervals, and provide usage data to energy companies and may also provide the data to customers at least once daily. Data are used for billing and other purposes. Advanced meters include basic hourly interval meters and extend to real-time meters with built-in two-way communication capable of recording and transmitting instantaneous data (EIA 2019b).

Before and sometimes concurrently with AMI deployment, some utilities use automated meter reading (AMR) systems. AMR also involves electronic meters, to eliminate the need for manual meter reads, but features only one-way communications, whereas AMI by definition includes two-way communications (DOE 2012). The DOE's review of the Smart Grid Investment Grants, which provided $3.4 billion in ARRA funding, builds on this definition, finding that AMI deployments around the country typically include the following:

- Customer-side smart meters that collect electricity consumption data in 5-, 15-, 30-, or 60-minute intervals
- Communications networks to transmit interval consumption data from the meter to the utility back offices
- A meter data management system (MDMS) to store and process the increased volume of data. The MDMS also integrates meter data with information and control systems, including head-end systems, billing systems, customer information systems, geographic information systems, outage management systems, and distribution management systems (DOE 2016, 10).[5]

To support new rate designs, these three elements are typically combined with customer-sited control technologies like programmable communicating thermostats and direct load

[5] The term *AMI* typically refers to a combination of these technology solutions deployed by electric utility investments. Gas and water utilities also deploy advanced metering, but less frequently than electric utilities. Webb (2018) found examples of natural gas AMI metering in only three states—California, New York, and Maryland—typically for dual fuel utilities, so this paper focuses only on leveraging AMI in electricity systems.

control devices, and with information technologies like in-home displays, web portals, and text/email alerts.

The Advanced Energy Economy offers a broader term than AMI, *advanced metering functionality* (AEE 2017b). AMF includes the following capabilities, many of which align with the energy efficiency use cases described in this paper, but it is agnostic as to which technologies are used and who deploys them.

- Collection of customers' usage data, in near real time, usable for settlement in relevant retail and wholesale markets for energy and ancillary services
- Automated outage and restoration notification
- Two-way communication between customers and the electric distribution company
- With customers' permission, communication with and control of smart devices
- Large-scale conservation voltage reduction programs or volt-VAR optimization
- Remote connection and disconnection of customers' electric service (while maintaining consumer protections)
- Measurement of customers' power quality and voltage

While no alternatives provide all the same functions as a widespread AMI deployment, other technologies can provide some aspects of AMF. These include the online portals for tracking solar PV output and consumption provided by solar companies, the separate networks and control centers managed by demand response companies, and home or building energy management systems. Similarly, smart thermostats and electric vehicle charging infrastructure can provide consumption data for a large end use, which can be aggregated by separate companies. Additionally, new companies are emerging that use radio-frequency sensors to capture data from legacy electric, gas, or water meters; these wireless energy monitors are being tested by one Midwest utility and may provide another alternative to AMI (Dan Forman, CEO, Copper Labs, pers. comm., June 18, 2019).

Further, although AMI can provide all of the advanced metering functionalities, some utilities with AMI rely on adjacent systems such as customer broadband or Wi-Fi to deliver some of those capabilities where real-time communications are needed. For example, Green Mountain Power's controllable heat pump water and space heaters communicate over customer Wi-Fi (Gold, Guccione, and Henchen 2017). Some AMI meters are installed with limited bandwidth for load management actions, and furthermore, some manufacturers have found it difficult or costly to register their devices on utilities' smart meter networks and therefore prefer a technology available in most homes.

History of AMI

Deployment of AMI began in the early 2000s as AMI technologies matured and their costs declined. Some of the earliest utility rollouts of AMI occurred during this period (Cooper 2017), although overall AMI penetration still was low. AMI received a large boost toward the end of the 2000s as a result of the Smart Grid Investment Grant funding included in the ARRA legislation of 2009. The number of meters quadrupled between 2007 and 2011, then investment proceeded at a slower pace from 2012–2016, doubling again during that period to reach nearly half of all meters, as shown in figure 1 (FERC 2019).

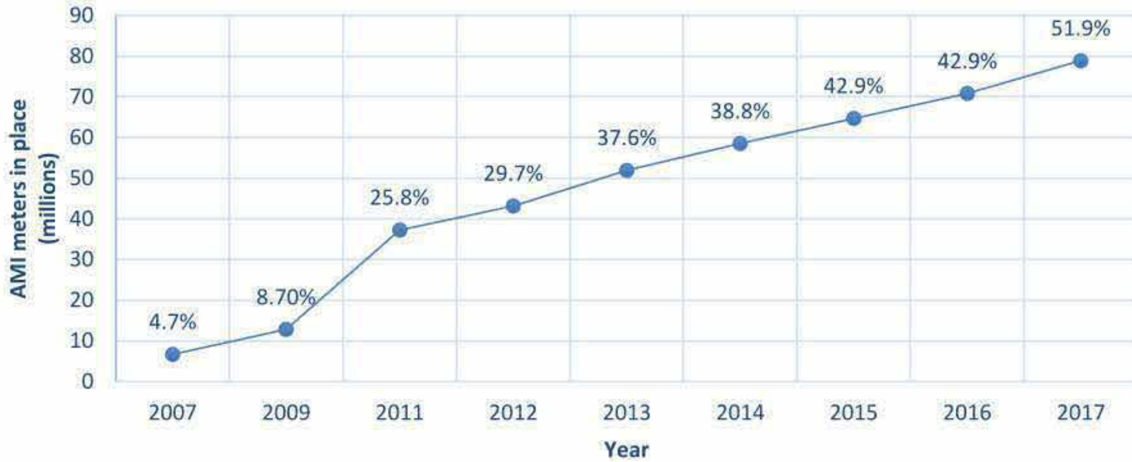

Figure 1. Estimates of advanced meter penetration rate (FERC 2019).

In 2007 there were about 6.7 million advanced meters in place, according to FERC. By 2016 this number had grown more than tenfold—to 70.8 million out of a total of 151.3 meters in the United States, a penetration rate of 47% (FERC 2019). And AMI continues to grow. The Institute for Electric Innovation estimates that AMI installations will reach 90 million by 2020, which will represent about 60% of all US households (Cooper 2017). Eventually virtually all customer metering is likely to be advanced, although this will take a decade or more, given past penetration rates.

A slight majority of the top 52 utilities in the United States had deployed AMI for most of their customers as of 2018 (EIA 2019a). A small subset (four) have penetration rates between 30% and 80%—possibly an indicator of a full AMI rollout in progress over several years or pilot programs in place. The remainder have AMI penetration of 17% or lower, with 10 of these at zero. These results show that utilities generally either have implemented AMI widely or have yet to do so to any significant degree.

A number of technological advancements have been critical for regulatory approval to support the growth of AMI, particularly customer communications through text messaging, online portals, paper and email reports, and, in early deployments, monitors and home energy displays (e.g., dashboards) that can provide energy use information in user-friendly, easily understood formats to customers. In addition, sensors, controls, and management systems can enable and automate responses using AMI data and customer inputs. AMI generates massive volumes of customer data. Consequently, advancements in information technology and management of large sets of data also have been necessary for the growth of AMI.

While AMI has grown rapidly in recent years and is well accepted in many states as a foundation of grid modernization, there are states and jurisdictions that have rejected AMI proposals by their utilities. Generally the reason cited is that AMI remains too costly relative to the benefits, or that utilities have not verified to the regulator's satisfaction the likelihood of those benefits (Walton 2018). In a few cases customer suspicions of alleged negative health impacts of AMI, such as radiation, have hindered rollouts (Hess and Coley 2012).

Benefits of AMI

Typical benefits of AMI in utility business cases include a combination of operational gains that accrue to the whole system and benefits that customers can directly take advantage of. Operational benefits result in cost savings for utilities and may result in rate decreases for customers, depending on the scale of those benefits relative to the cost of AMI installation. In contrast, customer benefits can include greater control over their energy usage and bills, leading to increased satisfaction and the potential for customer cost savings (and possibly energy savings). Some customer benefits accrue to the system as a whole, such as system capacity and energy benefits, but customer action is required in order to realize those impacts. In this section we describe the key operational and customer benefits cited in the business cases for AMI in our literature review, and we note their connections to energy savings.

OPERATIONAL BENEFITS

The inclusion of AMI in utility portfolios can lead to operational benefits that deliver reduced costs to the utility. DOE's 2016 review of the Smart Grid Investment Grant program in ARRA identifies four main operational benefits of AMI: reduced costs for metering and billing, reduced outage costs and less customer inconvenience, enhanced safety, and lower utility capital expenditures.

Lower costs for metering and billing come from the labor savings associated with fewer site visits to read meters and reduced truck rolls to check on lines, as well as lower labor costs from more accurate and timely billing, which reduces or eliminates estimated bills and reduces customer disputes (DOE 2016). AMI capabilities also can be used to provide customers with information on unusual usage patterns before they receive their bills, which may further reduce customer disputes. The Electric Power Board of Chattanooga (EPB) saved $1.6 million in annual O&M costs by using automated meter reading and remote services instead of on-site services (DOE 2016). Remote meter reading provides the most value for utilities with large AMI deployments and low customer densities (DOE 2016). However utilities that already have AMR, which provides one-way communication from the electric meter to the utility, may have already realized savings from fewer manual meter reads for service calls. Further, if AMR systems are not fully depreciated, the business case for AMI would need to include the costs of writing off any systems that have not reached the end of their useful economic lives (DOE 2012).

AMI can support outage notification and restoration by providing utilities with "the ability to detect, isolate, and respond to outages quicker than current capabilities" (NEEP 2017). Because utilities are able to detect and isolate outages faster with AMI, they can strategically dispatch repair crews, decreasing outage duration and customer inconvenience (DOE 2016). Utilities can also combine AMI capabilities with outage management systems (OMS) and geographic information systems (GIS) to create more detailed outage maps to share with the public (DOE 2016). Deployed in this way, AMI can increase system reliability and resilience for communities, especially in areas that are prone to severe weather events.

A qualitative benefit of leveraging AMI is increased safety for communities, businesses, and utility systems. "Sensors provide the opportunity for detection and reporting of methane leaks, corrosion potential, arc fault, and stray voltage" (NEEP 2017). With these data, utilities can troubleshoot problems remotely and more quickly respond to system emergencies. Utilities can also use automated data collection to better comply with safety standards, reducing risks from noncompliance (NEEP 2017).

With AMI, utilities can give their customers the tools they need for energy efficiency and demand response, reducing consumption and shifting energy use from peak to off-peak times (DOE 2016). While demand response can involve direct control of loads, utilities can also use pricing tools, like time-based rates and incentives, and informational tools, like customer bill alerts, to encourage more-efficient consumption. Where customer usage is effectively reduced or shifted away from peak times, utilities can deliver system benefits including fuel savings, market price suppression, and avoided line losses (Lazar and Colburn 2013). These benefits can lead to lower utility capital expenditures through reduced need to invest in capital-intensive infrastructure, and avoided greenhouse gas (GHG) emissions (DOE 2016).[6] Although these are system benefits, they require customer action that can also result in customer bill savings and other benefits associated with energy savings.

Another potential benefit is use of AMI data for utility system planning, particularly for the load forecasting aspects of distribution system planning and integrated resource planning. For example, Burbank Water and Power used AMI data to size distribution transformers and circuits more accurately by using actual peak coincident load on transformers instead of the worst-case scenario as an assumption (Hamer 2015). However we found no significant examples of the impacts of this use case on energy efficiency in our research, so we did not examine it in depth in this report.

CUSTOMER BENEFITS

Customer benefits include feedback and pricing that encourage or enable them to lower their bills, and improved satisfaction from better communication with their utility about billing, outages, and the sources of energy use in their home. In addition, utilities can deliver more-effective and better-targeted programs using AMI data, which can provide bill savings both from reductions in purchased energy and from rate reductions enabled by utility cost savings.

Tools like smart thermostats, web portals, and mobile apps coupled with behavioral cues can give customers more information and control over their electricity consumption, costs, and bills (DOE 2016). Utilities can leverage insights from interval data to present customers with their usage information in near real time through online portals and applications, as well as through phone calls, text messages, email, and even paper mail. AMI also facilitates the introduction of behavioral demand response, peak-time rebates, and other time-varying behavioral and pricing signals, enabling customers to respond more deftly to pricing and control signals. In addition, bill alerts can increase energy savings (Fulleman 2019), and

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[6] We discuss how AMI is used to create time-based rates and give examples of time-of-use (TOU) programs in our section on Energy Efficiency Use Cases.

more accurate billing information can decrease complaints and help avoid bill arrearages (NEEP 2017). These features may be particularly useful to low-income customers.

These customer benefits require customer engagement and as a result may require additional back office tools to store and process data. Customer engagement systems and back office tools may raise initial AMI deployment costs, but without them AMI is unlikely to deliver on customer benefits. Green Mountain Power (GMP) qualitatively measures societal benefits of its AMI deployment, such as commercial and industrial outage cost reduction, decreased energy costs, and energy conservation connected to AMI-based web portals (NEEP 2017). As a result of system cost savings, GMP was able to lower customer rates. Additionally, GMP call center representatives report that customers gained a better understanding of energy usage from having access to granular data (NEEP 2017).

Customer-facing control and information technologies are typically required in order to realize the potential benefits from better customer decision making about their energy use (DOE 2016). Control technologies include programmable controllable thermostats and home and building energy management systems, and information technologies include web portals, smartphone applications, and in-home or voice-activated devices to make customer energy usage data more visible and actionable. Such technologies may be provided by utilities, by contracted agents of utilities, or by third-party solution providers interacting with customers; as a result, availability of granular data can create benefits for these market participants as well.

Now we describe the use cases of mechanisms for AMI that support energy savings. These use cases directly and indirectly lead to the operational and customer benefits we have just discussed.

Energy Efficiency Use Cases

ACEEE's survey of the top 52 electric utilities by sales collected information on how they are leveraging AMI to save customers energy. Where information was available, we captured which utilities had the following programs or program measures:

- Near-real-time energy use feedback to customers
- Behavior-based programs with customer feedback and insights[7]
- Time-of-use (TOU) rates[8]
- Programs using data disaggregation
- Grid-interactive efficient buildings
- Conservation voltage reduction (CVR) or volt/VAR optimization (VVO)

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[7] Note that for the purposes of the initial survey, we focused on behavior-based programs that are energy efficiency measures. As a result, this data set does not consistently include behavioral demand response, which does produce some incremental energy efficiency savings (see Feedback section for details).

[8] For the purposes of the survey, we looked at time-of-use rates only; the rest of this paper considers time-varying rates, which include but are not limited to time-of-use rates.

Definitions of each of the above use cases are provided in Appendix B. Table 1 shows which utilities included the above program measures in their energy efficiency portfolios in program year 2018. Utilities with less than 25% AMI penetration are not included in this table.

Table 1. Prevalence of use cases for leveraging AMI to save energy among top 52 electric utilities by sales in program year 2018

Utility	Near-real-time feedback to customers	Behavior-based feedback	Conservation voltage reduction (CVR)	TOU rates	GEBs*	Data disaggregation
Portland General Electric	•	•	•	•	•	•
Southern California Edison	•	•	•	•	•	•
Commonwealth Edison	•	•	•	•		•
NV Energy		•	•	•	•	•
AEP Ohio (Ohio Power)	•	•		•		•
AZ Public Service	•	•		•		•
Baltimore Gas and Electric	•	•		•		•
Consumers Energy	•	•		•	•	
CPS Energy	•	•	•		•	
DTE Electric	•	•		•		•
PECO Energy	•	•	•			•
Salt River Project	•	•	•	•		
Duke Energy Carolinas (NC)		•	•	•		
Georgia Power	•	•		•		
San Diego Gas & Electric	•	•		•		
WI Electric Power	•	•		•		
Ameren IL		•		•		
Duke Energy OH		•		•		
Duke Energy SC		•		•		
PG&E		•		•		
PPL Electric Utilities		•	•			
Alabama Power				•		

Utility	Near-real-time feedback to customers	Behavior-based feedback	Conservation voltage reduction (CVR)	TOU rates	GEBs*	Data disaggregation
Duke Energy IN		•				
Florida Power & Light				•		
OK Gas and Electric				•		
West Penn Power				•		
Total	14	22	9	22	5	9

* Grid-interactive efficient buildings. Where utilities have a third-party program administrator in their service territory, some programs may be offered by that entity. For use case definitions, see Appendix B.

Portland General Electric

Portland General Electric (PGE) is one of only two utilities that reported using AMI for all six of the surveyed use cases. The utility maintains a separate AMI operations department that is responsible for collection, storage, and analysis of data, as well as export to other departments like billing and customer programs. PGE first implemented AMI for all customers in 2011. It reports that the company has improved on customer-facing applications for the data over time and is working to expand use cases for AMI, particularly in transmission and distribution management applications (Kirk Page, lead network data operator, and Erik Cederberg, AMI manager, PGE, pers. comm., November 25, 2019). These applications include two customer portals, EnergyTracker for residential customers and Energy Expert for commercial customers, which provide near-real-time data, data disaggregation for key end uses, behavioral tools like goal setting, and connections to Energy Trust of Oregon energy efficiency programs. The utility is testing time-varying rates through its Flex (a time-of-use rate) and peak-time rebate offerings. PGE also uses AMI for billing alerts, EM&V for demand response programs, and some small conservation voltage reduction pilots.

In addition to PGE, Southern California Edison also leverages AMI for all six use cases. Commonwealth Edison (ComEd) and NV Energy both leverage AMI for five different use cases. Seventeen utilities leverage AMI for two to four use cases, and six utilities report using AMI for only one use case. Utilities that have less than 25% AMI penetration are not included in this table. AEP TX and Oncor Electric Delivery have greater than 25% AMI penetration, but they do not include any of the listed use cases in their portfolios.

Of the utilities with 25% or greater AMI penetration, behavior-based feedback and time-of-use (TOU) rates were the most prevalent, with 22 utilities implementing each of these measures, respectively. Behavior-based feedback for energy efficiency, as described below, does not require AMI data but can use AMI data to enhance the customer experience. Similarly, while AMI enables more successful implementation of TOU pricing, AMI is not required for TOU rates since the periods and pricing are set in advance.[9] In contrast, AMI is

[9] Some form of sub-daily metering is required, but AMR can serve this purpose.

required for effective deployment of more dynamic forms of pricing, such as peak-time rebates and real-time pricing. Real-time feedback and CVR were also prevalent use cases, with 14 and 9 utilities, respectively, implementing these measures. Nine utilities responded that they use data disaggregation to target and market relevant programs to specific customers, and four utilities offer grid-interactive efficient building programs.

Our interviews reflected these trends. Most utilities whose representatives we interviewed have programs that provide customers with feedback, and many use AMI to support time-varying rates. For example, NV Energy provides AMI data to customers via a website and mobile device app. Customers can access a portal that integrates billing and other services, including energy efficiency programs. There also is an online home energy assessment that identifies savings opportunities based on a disaggregation tool using AMI data. In addition to the use cases included in the *Utility Energy Efficiency Scorecard* survey, we identified three additional use cases of AMI: procurement and pay-for-performance (P4P), evaluation measurement and verification 2.0, and system efficiency.

Building on these results, our literature review and interviews with experts for the current study revealed seven total use cases by which AMI enables or supports energy savings, especially energy efficiency, although some also support customer benefits through demand response.

- Feedback
- Pricing
- Targeting for program design, marketing, and technical assistance
- Grid-interactive efficient buildings
- Procurement and P4P
- M&V 2.0
- Conservation voltage reduction

Figure 2 depicts these use cases. Starting at left, the first two cases are directly customer facing. The four in the middle are use cases where a utility or program administrator can deliver savings indirectly, by improving the performance and potential value of customer programs. Conservation voltage reduction, as well as planning (which we do not explore in this paper), are utility-facing use cases for AMI data that can indirectly deliver energy efficiency, but through operations or procurement rather than customer programs.

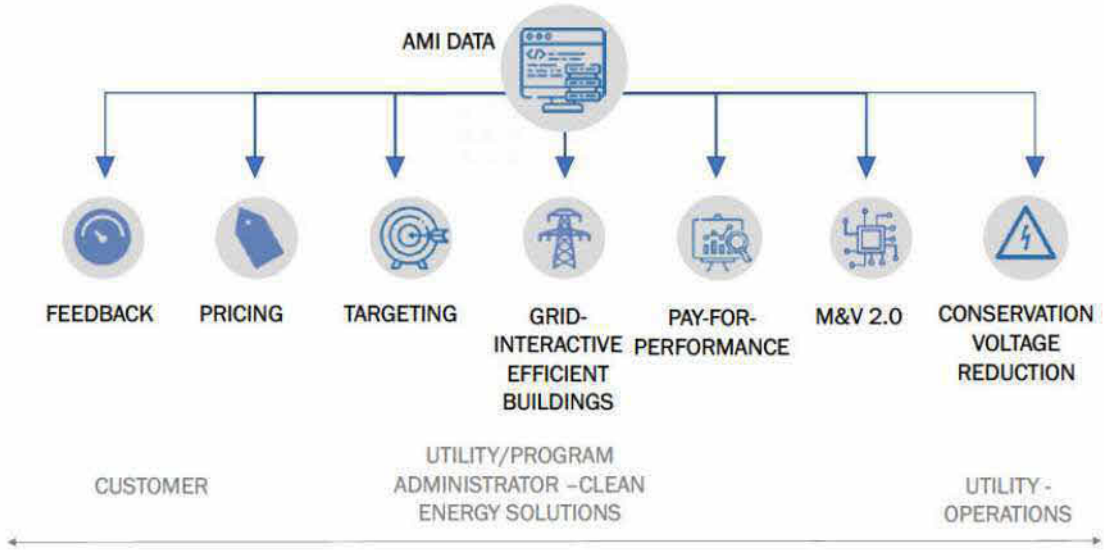

Figure 2. Use cases to leverage AMI for energy savings

Two of the use cases are driven primarily by customer actions: *feedback* of interval usage insights through information provision and *pricing* when customers respond to the more granular rates enabled by AMI. Utilities and third parties provide these informational, behavioral, and pricing signals, but customers are the primary actors. Other use cases are enabling mechanisms that work behind the scenes: usage segmentation and improved M&V are two ways that utilities, program administrators, and implementers can design more cost-effective, targeted programs. Other use cases focus on market animation and optimization of demand-side resources: using AMI data to enable procurement of and programs for those resources best positioned to meet system energy, capacity, and flexibility needs at least cost. Finally, AMI can support system efficiency through conservation voltage reduction, controlling voltage on distribution circuits and enabling some end use loads to draw less power.

We explore each of these potential use cases in the sections below, articulating how AMI can result in energy savings benefits. We document evidence of those savings where available from the literature or provided in our interviews with utilities and third-party service providers. In many cases, these use cases are largely underutilized by the utilities with AMI; as a result, much of the following section represents the opportunity rather than the reality on the ground today.

FEEDBACK

There are two principal types of feedback that can influence customer behavior related to energy use. Near-real-time feedback provides customers energy use data shortly after use is recorded. The exact interval between use and reporting varies according to technologies and practices in place but can be close to zero. Behavioral feedback applies the tools of behavioral science to enhance responsiveness to energy use feedback, whether by AMI or conventional metering. As we discuss below, providing customers near-real-time feedback based on AMI and using behavioral science tools can yield the largest impact on customer energy use.

AMI can provide highly granular feedback to customers on their energy use, which can both engage and empower them to take actions to reduce or otherwise modify such use. Rather than a single monthly reading that gets reported to customers about a month later (a lag due to manual reading of meters and monthly billing cycles), customers can receive near-real-time data on their energy use (depending on the meter's interval cycle and reporting technologies and methods). Data can be coupled and tracked with a variety of display technologies, such as a smartphone application or in-home display (smartphone apps being more prevalent). The AMI data also require appropriate software to convert it to information in a form that is readily understood by customers and that can motivate them to change their use. With timely data and clear reporting, customers can correlate different uses of electricity with the amount consumed. Such knowledge is fundamental to understanding and managing energy use within a home, business, or industry.

While energy use data alone can influence customer behavior, simply providing such data is insufficient to affect most customers' energy consumption. Experience shows that providing customers with personalized insights based on interval data (as a number of vendors do in their home energy reports or other communications) is much more effective at motivating customers and getting them to take actions to change their energy use. Such reports are a common application of behavioral feedback.

Studies on customer feedback suggest different degrees of impact. Buchanan, Russo, and Anderson (2015) conclude that there is limited evidence that feedback alone is effective in getting customers to reduce energy use. Karlin, Zinger, and Ford (2015), however, conclude that feedback is a promising strategy to promote energy conservation, but that this depends on how information is conveyed to customers (e.g., via social norms, anchoring, and other behavioral tools) to motivate them to take actions that affect their energy use. Sussman and Chikumbo (2016) find that most real-time feedback programs using opt-in designs report net electricity savings in the 5–8% range.

Program experience and studies of consumer behavior have shown that the best way to maximize the effectiveness of feedback is to provide it through an engaging medium, such as an interactive computer program, and in combination with additional strategies (Sussman and Chikumbo 2016). Strategies can include incentives, normative reporting (comparison with similar households, such as is provided in home energy reports), and personalization of information and messaging. To have the greatest impact, energy use feedback should be coupled with programs, services, and pricing that can motivate, assist, and reward customers for taking actions. In a pilot AMI program, CenterPoint Energy used a web portal to provide smart-meter customers with information on how to better manage their energy usage and costs, including education on steps to reduce peak demand. The pilot included prizes for successful responses. In 2011 the set of 198 participants reduced peak demand by an average of 5% during 10 events; some participants reduced consumption by as much as 35% (DOE 2016).

Mobile applications are another way to for utilities to provide feedback and can be an effective tool to engage customers. For example, DTE's behavior program uses a mobile application, Powerley, that gives customers energy usage insights and allows customers to set savings targets, interact with feedback tools, and see recommendations of energy efficiency measures targeted to their consumption patterns. Customers can request an Energy Bridge that uses AMI to collect one-minute energy usage information and gives customers real-time energy usage feedback through the DTE Insight app. Paired with home energy reports, in 2018 DTE's residential behavior change programs achieved 62.7 GWh of energy savings and reduced demand by 23.6 MW (DTE Electric Company 2019).

Survey research by the Smart Energy Consumer Collaborative certain types of residential customers are more likely than others to use AMI feedback to understand their energy use and take actions to change it, particularly segments the Smart Grid Consumer Collaborative terms "green champions" and "savings seekers" (SGCC 2016). This also applies to commercial and industrial customers. Most small businesses lack the expertise, time, and resources to actively manage their energy use (Nowak 2016). Larger customers—with higher energy use and costs—may devote necessary resources to actively managing energy use, such as a dedicated energy manager and technologies that can use both AMI data and related on-site metering of systems and equipment.

Program staff and third-party service providers we interviewed affirmed these observations. One provider noted that the level of customer engagement with AMI data and technologies is the key to energy savings from energy efficiency improvement and behavioral changes. Although we found a lack of evidence in the literature documenting a direct causal link between customer engagement and energy efficiency, the two behavioral program providers we interviewed cited internal evidence that those customers who are engaged are more apt to act on insights gained from AMI to save energy.[10]

Where AMI data are disaggregated, the insights from sharing a breakdown of large end uses can be a means to get customers more engaged because it makes the customer experience more relevant.[11] Another provider noted how AMI can be used to start a discussion with customers about their energy use and how they can make changes to save money, which can help create strong long-term relationships between customers and their utilities. Customer engagement tools and platforms (e.g., web portals and mobile apps) also can be effective for cross-marketing programs—linking use patterns with available incentives and services that may benefit customers. Such tools also can provide high bill alerts. Evidence from one randomized trial of a high bill alert email offering for 50,000 Xcel Energy customers in Minnesota found 0.4–0.6% annual savings per customer (Fulleman 2019). These customers did not receive other behavioral energy efficiency communications. While these savings are small in magnitude per customer, they can be large in aggregate in an opt-out design such as the one used in Minnesota. Further, there may be additional

[10] However, absent documentation, we note that there could be a reverse relationship, that saving energy causes people to pay attention to and engage with communications from the utility. There could also be a third variable explanation, for example that the type of people who pay attention might also be the type of people who would save energy anyway.

[11] This disaggregation is sometimes called nonintrusive load monitoring. We explore the value of this disaggregation for targeting and program design in the Targeting for Program Design, Marketing, and Technical Assistance section.

benefits from layering high bill alerts with home energy reports; internal analysis from eight different Opower programs found high bill alerts can boost Home Energy Report savings by 0.3% (JD Toppin, Global Practice Lead, OPower Solutions Consulting, pers. comm., December 4, 2019).

While AMI rollouts and associated efforts to engage customers have focused largely on the residential sector, AMI also can be used to engage and benefit commercial and industrial customers. Feedback from more granular data provided by AMI can provide insights on their energy use, just as for residential customers. As an example, Efficiency Vermont uses AMI in conjunction with a strategic energy management (SEM) program for commercial/industrial customers. The program model is for continuous energy improvement, a standard for SEM programs. Efficiency Vermont account management staff recruit cohorts of facility energy champions and their teams to participate in the program. SEM training includes an initial assessment of a facility energy management practice and then workshops on topics in energy management such as goal setting, energy efficiency topics, monitoring energy performance, and employee engagement. In addition, early in the workshop progression, a facilitated energy "treasure hunt" occurs to identify low- and no-cost savings opportunities, which are then pursued for implementation with help from the account management/energy consultant team working with the customer. These program elements are designed to engage customers and establish an ongoing relationship with them based on SEM. AMI provides vital, timely feedback that enables participants to monitor and validate results from actions they take to reduce energy use. AMI is an effective tool for EM&V and also is used to document savings and utility payments.

AMI feedback can also be used effectively for behavioral demand response programs, which use feedback to target reductions in peak power demand (kilowatts). This report does not focus on behavioral demand response, even though it requires AMI, because its primary function is to deliver peak demand reduction rather than energy savings. However a 2016 DTE program found 0.45% incremental electric energy savings in addition to 3.31% incremental coincident peak demand savings, demonstrating the potential for small additional energy savings beyond kW reductions from these programs (Kirchner 2017).

PRICING

While AMI data combined with customer engagement can better inform customers and may lead to direct savings, time-of-use pricing used in conjunction with these insights from AMI is often the key to unlocking the greatest customer savings and benefits (Faruqui, Sergici, and Warner 2017). Aligning rates with market and system costs that can vary widely by time of day and season provides signals and incentives to customers to modify their energy use.

Utility economists and analysts long have advocated for time-varying pricing as a means to optimize generation resources and grid performance. This type of pricing also would provide market-based price signals to customers, enabling them to reduce their costs by changing energy use behavior and making energy efficiency improvements. But until AMI technology matured and became cost effective, such arguments for more-advanced pricing remained largely rhetorical.

Costs of power production and wholesale electricity markets are dynamic. Prices for electricity can vary widely due to system power demand and the different costs of production and delivery among electricity suppliers. Generally, the highest prices for wholesale power occur during times of peak demand—times when the most expensive generating resources need to be used and grid constraints may limit bulk power transfers. Historically and currently, retail electricity rates for most customers are flat; they do not reflect wholesale market prices and time of use. The same rate applies regardless of when the electricity is used; there is no seasonal or daily variation.

Time-varying, or dynamic, rates have long been advocated and have been used in certain cases to better reflect the dynamic nature and costs of wholesale electricity markets. There are a few types of time-varying rates, outlined in Baatz (2017):

- *Time-of-use rates.* TOU rates may vary by time of day and season to align with daily and seasonal variations in power generation costs and market demand. TOU rates also send price signals to customers related to future investments. High rates that occur at times of peak power demand can encourage customers to reduce use during peak periods, thereby helping utilities avoid or defer investments in new infrastructure.
- *Real-time pricing.* RTP is a structure in which customer rates vary directly with real-time wholesale market rates.
- *Critical peak pricing.* CPP assesses a higher energy rate (often over $1 per kWh) during an announced event for a limited number of hours, on the basis of higher wholesale electricity prices and allocation of costs for capacity needed at peak load. The announced events are often limited to a certain number per year.
- *Peak-time rebate.* While not technically a rate structure, PTR awards customers with a rebate for energy saved during announced peak events, typically announced in advance. It provides a financial signal and incentive to customers as to varying costs according to time of use.
- *Variable peak pricing.* VPP charges customers a higher rate for a predefined peak period. The price component on-peak can change each day, with a constant off-peak price.

AMI enables the implementation of TOU rates while providing a way for customers to track their usage in the specified time-based intervals and understand how they can respond to the rate. AMI can also support a bill comparison tool and "shadow" billing, which helps customers predict what their bills would be if they switched to a different rate. However the periods and pricing are set in advance for TOU, not based on real-time prices, so AMI is not required (Colgan et al. 2017).[12] In contrast, critical peak pricing, peak-time rebates, variable peak pricing, and real-time pricing all rely on advanced metering data due to the nature of these rate structures and their dependence on timing of events or wholesale market fluctuations. These rate structures also require some means in place to notify customers of changes in prices, such as via text messages, mobile device applications, or in-home

[12] Colgan et al. (2017) note, "Meters with multiple registers can be read with conventional meter reading equipment," which is why TOU is possible without AMI.

displays. For time-varying prices to have an impact on customer behavior, their effect on customer energy bills needs to be reasonably predictable. Customers also need general education to understand how pricing is structured, how it may affect them, and how they can take advantage of such programs to reduce costs.

Some of the first time-varying rate experiments occurred in the 1970s (Faruqui and Malko 1983). However application of time-varying rates by utilities did not occur to any large degree until the early 2000s, triggered in part by California's energy crisis of 2000–2001 and the emergence and availability of AMI technologies that could be deployed at scale and reasonable cost. Numerous studies of time-varying rates provide overwhelming evidence that customers respond to changes in volumetric (kilowatt-hour) rates (Baatz 2017). For example, a meta-analysis of more than 60 residential pricing pilots from 57 utilities across nine countries and four continents concluded that there is compelling evidence that customers respond to price changes (Faruqui, Sergici, and Warner 2017).

Recent deployments at utility scale in the United States and Canada are demonstrating that customers are accepting and benefiting from time-varying rates. Rollouts of TOU rates in Arizona, Oklahoma, Sacramento, Ontario, and Fort Collins, Colorado, have been well accepted. Customers see opportunity to save money by changing their behavior (Faruqui and Bourbonnais 2019).

Results from the Smart Grid Investment Grant program, which was part of ARRA, demonstrate clearly the impacts possible from implementation of time-varying rates (DOE 2016). Table 2 presents examples of these results.

Table 2. Customer bill savings from selected time-varying pricing programs

Utility	Bill savings	Program year(s)
Baltimore Gas and Electric	• $9.08 average credit paid per customer for four energy savings days • $2.8 million in bill savings for all 700,000 participants in the Smart Energy Manager Program, which included behavioral demand response	2013
Burbank Water and Power	• More than $1 million in bill savings for all 25,000 participants in TOU rate program across all program years	2011–2014
Green Mountain Power	• For customers on peak-time rebate and critical peak pricing, average savings across 14 events of $2.52–$4.88 • Estimated total annual bill reduction of $50/customer	2012–2013
Oklahoma Gas and Electric	• Average annual savings of $191.78 for residential customers and $570.02 for commercial customers in the VPP pricing pilot program	2012

Utility	Bill savings	Program year(s)
Sacramento Municipal Utility District	• Average summer bill savings exceeding $77 on the TOU-CPP rate • Average annual bill savings of nearly $40/year for customers who checked out and used an in-home display from the utility	2012–2013

Source: DOE 2016

Reducing costs is clearly the primary motivation for customers to change their energy use in response to TOU pricing. The corresponding reductions in overall energy consumption and peak demand reveal the magnitude of the responses. Table 3 shows results from a previous ACEEE review of 50 studies of TOU and other time-varying pricing mechanisms (Baatz 2017).

Table 3. Average and median peak demand reduction and reduction in overall consumption from 50 time-varying pricing studies

Rate treatment	Number of studies	Average peak demand reduction	Average reduction in overall consumption	Median peak demand reduction	Median reduction in overall consumption
CPP	13	23%	2.8%	23%	2.6%
PTR	11	18%	2.3%	18%	0.6%
TOU	17	7%	1.2%	6%	1.0%
TOU+CPP	8	22%	2.1%	20%	2.3%
TOU+PTR	1	18%	7.4%	18%	7.4%
All	50	16%	2.1%	14%	1.3%

Clearly TOU pricing and other time-varying pricing mechanisms can be effective in changing customer use of electricity to optimize grid performance and yield cost savings to customers. To put the above savings in context, most state energy efficiency resource standards set annual energy savings targets in the range of 1–2% from all customer energy efficiency programs in a utility portfolio. The results shown in table 2 also reveal that while time-varying pricing does yield reductions in overall energy consumption (kWh), the biggest impacts are on peak demand (kW) reductions. In this way, time-varying pricing functions primarily as a demand response strategy—a means to shape demand and create a more flexible grid.

Customer responses can be automated with various information and control technologies. Such technologies include in-home displays, web portals, and text/email messaging that provide energy use data in formats that are visually appealing, easily understood, and able to guide customers toward beneficial actions to change their use. For example, web portals can provide customers both historical and near-real-time usage data. Home HVAC controls, such as a smart thermostat, can be programmed to adjust settings and operation of equipment such as central air conditioners to respond automatically to price or other signals from grid operators or third parties. This type of functionality can also be achieved without AMI, although AMI deployments can deliver much greater scale for customers served and impacts. Faruqui, Sergici, and Warner (2017) find a 69% reduction in on-peak usage where these rates are paired with AMI and other technologies—from 6.5% for every 10% increase in the peak-to-off-peak price ratio to 11% for every such increase.

AMI can also be used by utilities for prepay plans. These require customers to pay in advance of receiving electricity. Such plans are controversial as electricity is cut off when a customer's balance reaches zero. There usually is only a very short grace period (e.g., one day) compared with those under traditional billing plans.[13] Research by ACEEE and Slipstream found that customers reduce their consumption by about 9% on prepay plans, but the reason for these savings is unclear (Sussman 2019). The combination of enhanced feedback and threat of shut-off is particularly likely to reduce energy use, but other factors may also explain these findings. Although customers generally like prepay plans, such programs can pose risks to certain customers—those who are extremely budget constrained and vulnerable to loss of service.

TARGETING FOR PROGRAM DESIGN, MARKETING, AND TECHNICAL ASSISTANCE

With limited budgets and concerns about the rate impacts of programs, program administrators need to maximize the value of each program dollar spent, especially with continuing cost-effectiveness challenges at some utilities. Energy efficiency targeting is one means of improving program effectiveness (increasing savings, lowering the cost of serving or recruiting customers) by selecting customers with particular characteristics as the focus of marketing efforts. Borgeson and Gerke (2018) describe three strategies for targeting. Utilities can focus on customers who: (1) are able to participate (e.g., have the relevant end uses), (2) are likely to participate, or (3) are likely to save more than others when they do participate.

Some strategies do not rely on AMI, instead using other forms of data—monthly usage data, demographic information, past program participation, and other characteristics—to target customers. Examples from national labs, software companies, and utilities suggest that interval data can add value to program targeting by helping to answer whether a customer can participate, and whether she is likely to save more if she does.

Identifying Whether a Customer Is Able to Participate

Where interval data enable segmentation of end uses, they might be used to determine whether a customer can participate in a program; for example, for a residential pool pump program, interval data might locate customers who have a pool. This segmentation uses nonintrusive load monitoring (NILM), which employs data from a single point of monitoring, like a smart meter, to provide an itemized accounting of end-use energy consumption (Baechler and Hao 2016). NILM analysis compares these data with appliance signature databases that catalog physical measurements of appliance load (Armel et al. 2013).

[13] Prepay plans also typically have certain blackout periods (times when power cannot be shut off), such as overnight, on holidays, and on weekends. Customers are usually shut off at the earliest time legally permittable under applicable regulations and rules.

Most AMI data are reported on a 15-minute, hourly, or daily basis, and at this level of disaggregation, some software vendors for NILM have faced challenges recognizing loads and identifying key events for complex equipment, like different phases of operation (Baechler and Hao 2016). Software vendors report significant improvements in performance since 2016, suggesting the importance of continued testing that measures how well NILM can recognize loads. The ability to disaggregate end uses increases with the granularity of the data. Hourly data can identify loads that correlate with outdoor temperature (like HVAC), continuous loads, and time-dependent loads (like pool pumps and outdoor lighting). One-minute data can identify as many as eight different appliance types, with increasing numbers of appliances for data in the multiple kHz or MHz range (Armel et al. 2013). Some devices, like the Sense Home Energy Monitor, are installed in the home and use a Wi-Fi network instead of an AMI meter to perform the disaggregation.

Despite these reliability challenges, the market for NILM is growing, with about 60 vendors offering these services as of 2016 (Baechler and Hao 2016). Because NILM techniques can identify some of the largest end uses, like heating and cooling, as well as unique time-dependent loads like pool pumps, they can be used to identify customer eligibility for some types of programs. These techniques can also be used to assess whether customers are good candidates for meter-based P4P programs (described below). For example, the Sacramento Municipal Utility District (SMUD) identified which buildings had good "fitness" for the Time-of-Week and Temperature model developed by Lawrence Berkeley National Laboratory (LBNL), finding that restaurants did well but that colleges and schools varied more, depending on whether classes were in session, which was not included in that model. Model quality is one contributor to the overall robustness of meter-based savings results (Berkeley Lab 2018). We found in our interviews that opportunities to use the outputs of NILM to improve energy efficiency program performance are generally underutilized, although some utilities and vendors are working together to pilot such use of these algorithms.

Identifying Whether a Participant Is Likely to Save More than Others

Usage data, especially interval data, can also be used to prescreen potential program participants on the basis of their usage patterns so recruitment efforts can focus on the most promising customers. In this way, targeting has the potential to improve cost effectiveness by increasing savings and reducing the likelihood that there will be customers who fail to achieve energy savings benefits from the program.

Most estimates of energy efficiency savings are based on average cases or at best a range. Scheer et al. (2018) investigated the metered savings performance of several energy efficiency programs across both residential and commercial sectors. In each case the authors identified characteristics derived from customers' preprogram AMI data that were highly predictive of actual metered savings outcomes. Figure 3 shows results for customers in California's Central Valley who participated in Pacific Gas and Electric's (PG&E) Advanced Home Upgrade pathway (AHUP) of the Energy Upgrade California program. AHUP is a home retrofit program consisting of building shell and HVAC measures. The figure's two panels show the distribution of metered annual MWh savings for customers in the top half and bottom half of two targeting criteria: summer usage and summer-to-shoulder kWh ratio. Customers in the top half of this targeting scheme saved nearly 3.5 times more than customers in the bottom half. Similar patterns were observed for every program studied (with different targeting schemes, depending on the program). This research clearly highlights the potential to improve savings and cost-effectiveness by basing targeted interventions on customers' usage patterns.

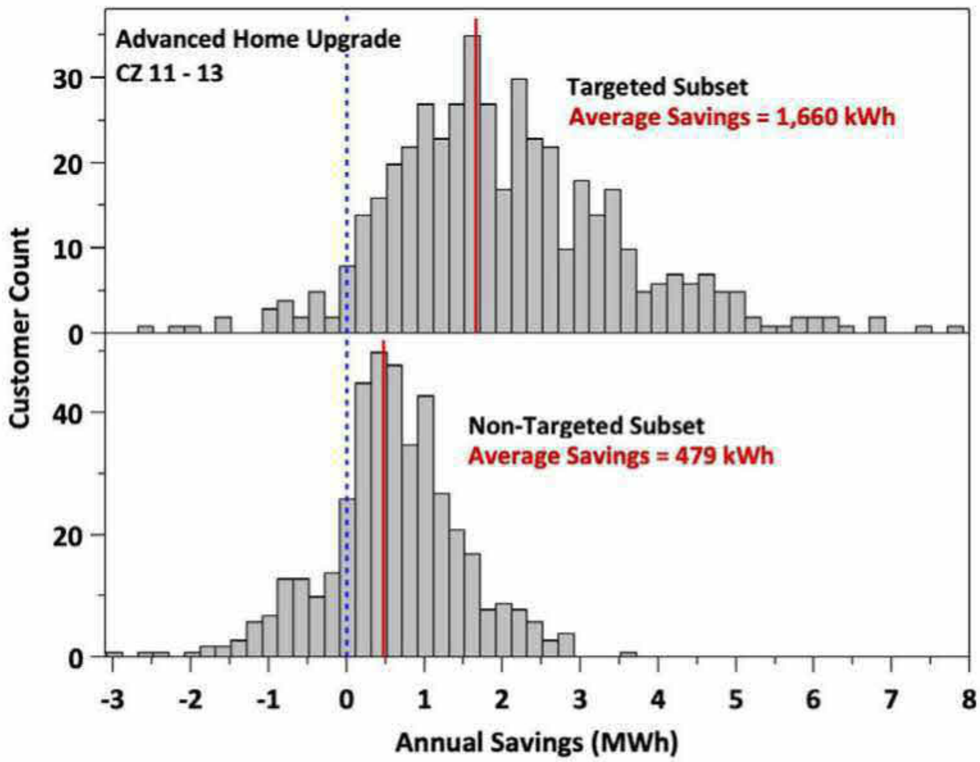

Figure 3. Distribution of pre/post annual cooling electricity usage for Advanced Home Upgrade participants in California's Central Valley. Top: top half of customers as gauged by the targeting criteria. Bottom: bottom half of customers as gauged by the targeting criteria. *Source:* Scheer et al. 2018.

Although monthly data can and should be used to target programs for which AMI data are not available, interval data allow more precise targeting and enable targeting schemes that rely on segmentation of usage, like discretionary kWh, peak-period usage, baseload kWh, load-shape characteristics, and more precise determinations of heating and cooling kWh. For HVAC programs, the PG&E team found that targeting based on total usage was less effective than using interval data, which enabled researchers to better isolate the portion of usage from cooling and derive additional parameters (Scheer, Borgeson, and Rosendo 2017; Borgeson and Gerke 2018). These techniques were not limited to residential programs; PG&E research also estimated the potential impact of targeting across a range of residential and small and medium-size business programs and estimated that such targeting would increase average participant savings by 53% and 76% (Scheer et al. 2018).

These research exercises informed targeting strategies that are now being deployed within PG&E's meter-based P4P programs.[14] These programs will provide in-field experience with targeting to maximize total savings and savings depth. In the meantime, it is clear that PG&E sees targeting as an important strategy, as described in its *Energy Efficiency Business Plan 2018–2035*: "AMI data offers PG&E the ability to better understand site-specific customer energy usage and to tailor offerings that benefit customers most in need of specific energy efficiency offerings . . . PG&E plans to target customers who are expected to yield the greatest energy savings, energy bill reductions, and/or grid-value" (PG&E 2018, 1–9).

For effective targeting, program designers will need to balance increased savings from more rigorous targeting criteria with increased pressure on program recruitment from a smaller segment of the population. Targeting may also raise equity concerns by eliminating customers with lower likelihood of savings; to mitigate these concerns, program designers will need to ensure that targeting strategies also focus on desired customer attributes such as disadvantaged community designations. It should also be noted that energy efficiency is often a priority or first-in-the-loading-order resource expected to deliver cost-effective savings that benefit the entire rate base. Targeting the customers who can drive the greatest value can enhance benefits for all customers. Finally, the value of targeting is dulled by traditional deemed approaches, which average savings across all customers and thus reduce the motivation and accountability for improved results from targeting.

Using Targeting to Improve Technical Assistance

Utilities can take insights about which customers are most likely to participate in and benefit from programs directly to the customers themselves in the form of improved technical assistance. Although these insights can be used in feedback as described above, they can also be used in customer interactions with utility representatives or contractors. If such insights are integrated with databases and the workflow of customer call center representatives, large account managers, and contractor trade allies, they can be used to help customers diagnose high bills and connect customers to utility offerings.

PECO offers an example of a utility using data from AMI to target customers and better market programs. It recently began an effort working with a third-party implementer to disaggregate end uses with AMI data in an e-audit tool and then use these data in email campaigns that target small and medium-size businesses. In addition, large account representatives use these assessments, including highly visual "heat maps" of buildings' energy use at different times of day, to facilitate conversations with customers about how they are using energy (Mike O'Leary, Manager of Energy Efficient Programs, PECO, pers. comm., August 29, 2019).

The targeting, marketing, and program design described above can be used by a range of market actors, including utilities themselves, other program administrators where third-party (e.g., Energy Trust of Oregon) or hybrid (e.g., NYSERDA) models exist, and program

[14] PG&E did not self-report data disaggregation as one of its use cases in our survey, suggesting either that it has discontinued the practice or that the survey respondent was not aware of these activities within the company's large energy efficiency program team.

implementers who acquire savings on behalf of program administrators. In addition, the "platform" model of distribution utilities explored in New York's Reforming the Energy Vision process envisions other service providers using these data directly in the marketplace, perhaps absent "programs" per se (New York PSC 2016).

GRID-INTERACTIVE EFFICIENT BUILDINGS

Many states increasingly face growing peak electricity demand, transmission and distribution infrastructure constraints, and an increasing share of variable renewable electricity generation (Neukomm, Nubbe, and Fares 2019). These stresses to the grid create an opportunity to expand the role of flexible, controllable electricity loads to support reliability and lower system costs. Traditional demand response can serve this role, but so too can grid-interactive efficient buildings (GEBs).[15] These buildings are energy efficient, can be demand flexible, and can be optimized with multiple technologies (possibly including customer-sited generation and storage) for customer and grid benefits. GEBs essentially combine the AMI use cases discussed above: pricing, feedback, and targeting. The technologies required for GEBs also can enable other use cases, namely P4P and M&V 2.0.

To serve these multiple roles, GEBs require information and communications technologies—interval data from either AMI or building automation systems (to understand the best ways to respond to grid needs) combined with controls both for the building and for communications back to utility or aggregator offtakers of the building's services. These data and controls can be used to support GEBs in utility program offerings or can be a part of GEB projects implemented by third-party aggregators and building owners.

To date there are only limited examples of GEBs, especially through utility programs. ACEEE's recent brief (Perry, Bastian, and York 2019) on this topic concludes that no programs or pilots can be considered a holistic GEB program. However we identify a number of utility programs and pilots that promote aspects of the GEB vision for programs, as shown in figure 4.

[15] GEBs are grid-connected buildings with information and communications technologies able to respond to signals from the grid to modify energy demand. They actively use distributed energy resources (DERs) and optimize energy use for grid services. Utilities can use GEBs to manage grid operations and lower system costs while delivering customer value in the form of reduced bills, improved productivity, and enhanced comfort. The energy efficiency aspects of GEBs can also make large contributions toward meeting state, municipal, and utility energy efficiency and emissions goals.

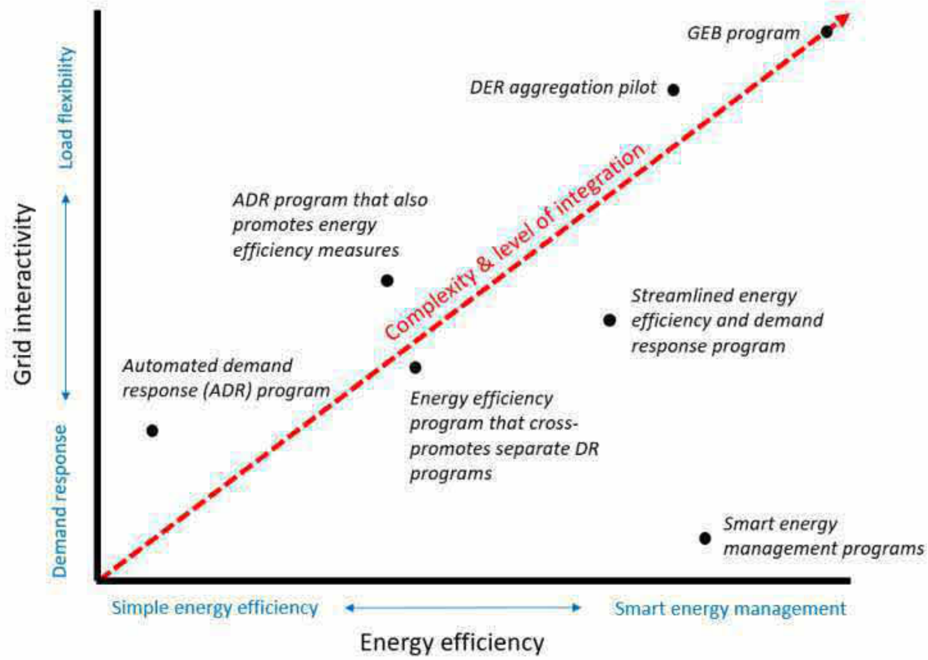

Figure 4. Various types of grid-interactive and energy efficiency offerings scaling up to fully integrated programs

In our survey, four utilities said they are running GEB programs, and these appear to be automated demand response programs (ADR) that also offer energy efficiency measures and integrated energy efficiency and demand programs that use smart thermostats to deliver customer and grid benefits. For example, PG&E's ADR program offers additional incentives to participants who install energy efficiency measures at the same sites that participate in demand response events. This program also requires participating facilities to undergo an on-site audit that identifies both demand response and energy savings opportunities (Perry, Bastian, and York 2019). While these programs do not require AMI, advanced metering can support GEB development through its ability to quantify and capture the time value of savings. This yields concrete value streams both to customers with GEBs and to grid operators.

One opportunity to better value the multiple services that energy efficiency provides is to base utility procurement on the actual performance of energy savings, capacity, or flexibility resources. Where these P4P models value peak savings, they typically leverage AMI data to measure the performance of demand-side resources.

PAY-FOR-PERFORMANCE

P4P, an emerging model for energy efficiency program design, rewards energy savings on an ongoing basis rather than providing up-front payments based on deemed or custom measured calculations. These meter-based P4P programs determine performance payments based on savings quantified using meter data, including daily or hourly data from AMI where available (Best, Fisher, and Wyman 2019). Meter-based P4P programs aim to produce a series of benefits for program administrators (typically utilities) and their customers (Best, Fisher, and Wyman 2019).

Some of the benefits of meter-based P4P are not AMI dependent. Monthly billing records can still be used to calculate avoided energy consumption. Using standardized methods of accounting for savings and delivering performance payments can help increase investor and utility confidence that energy efficiency is a quantifiable, reliable resource, which may help energy efficiency programs scale.[16] Meter-based P4P can also reduce the need to oversee program implementers by setting competitive procurement requirements and then letting implementers determine how to best incentivize customer adoption. Finally, these program designs can break down silos between programs and enable integration within customer offerings by letting a broader range of technologies participate if they can meet program savings requirements.

Currently, the meter-based P4P landscape includes some program administrators without AMI, like Energy Trust of Oregon and the NYSERDA–National Grid collaboration launching in 2020. Others, like PG&E, the DC Sustainable Energy Utility (DC SEU), and NYSERDA's collaboration with Con Edison, do leverage AMI. In interviews, NYSERDA cited additional potential benefits from meter-based P4P with AMI: alignment with greenhouse gas reductions and grid needs and continuous improvement in program design. AMI also enables program administrators with meter-based P4P to offer data to implementers to support program targeting that relies on usage segmentation, like peak-period usage, baseload kWh, and load-shape characteristics, as described above.

With daily, hourly, or 15-minute interval data, program administrators can set performance payments that scale based on the value offered to the grid or on GHG reduction at different hours of the day or different locations. This is currently being done in multiple PG&E residential P4P programs where savings achieved during the summer peak period are assigned a 3x payment kicker. Similarly, program administrators can offer localized incentives in night-peaking residential areas or midafternoon-peaking commercial areas on the same summer day. While utilities can use average load and savings shapes to value savings happening during system peaks, interval data offer a more accurate, granular understanding of the time value of energy efficiency and localized impacts on the grid. For example, figure 5, below, shows how a California home-upgrade program delivers significantly more annual avoided GHG emissions per MWh of savings than a commercial program (that consists of mostly lighting and refrigeration measures), given the time dependence of marginal emissions rates through the day on each day of the year. This value will be most important in states and service territories focused on carbon or on grid constraints, or where measured load shapes do not provide sufficient information.

[16] One example of a standardized method used in meter-based P4P is CalTRACK (caltrack.org), which provides detailed, executable approaches to calculating changes in consumption. When operationalized with an open-source code base, it significantly improves transparency for market actors over traditionally custom-designed evaluations using professional guidelines like Uniform Methods or various state EM&V protocol documents.

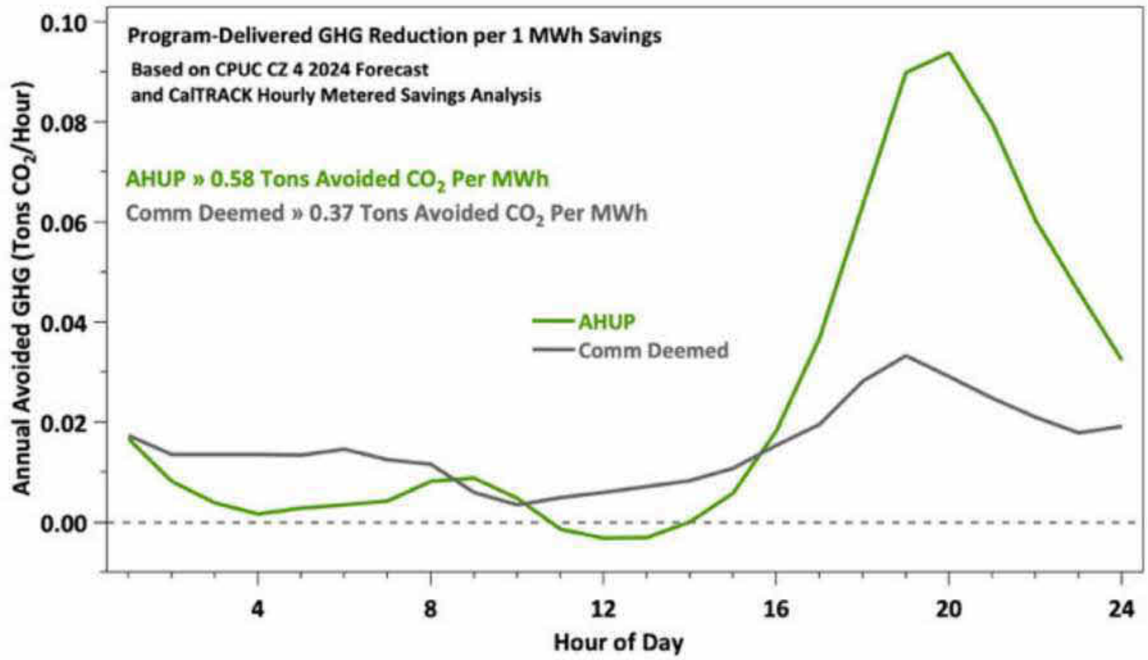

Figure 5. Avoided GHG emissions for 1 MWh of savings from Pacific Gas & Electric's Advanced Home Upgrade program and Commercial Deemed program. Each data point multiplies 365 hourly kWh savings measurements with associated marginal emissions to calculate annual avoided GHG at each hour of the day. *Source:* Golden, Scheer, and Best 2019.

Meter-based P4P with AMI allows program administrators to create actionable insights about how to improve programs while they are happening by tracking meter-based impacts close to real time rather than months after the end of a yearlong program. Interval data also generally allow for better modeling of energy consumption. With better models, evaluators, utility planners, and investors can have more confidence in the savings, and program administrators, and perhaps even policymakers can better forecast results before the end of program cycles in order to make key adjustments (for example, to targeting strategies and quality assurance requirements).

Even those programs that do leverage AMI for some purposes may not use its full functionality in initial pilots. Program implementers may roll up their AMI data to a less frequent interval, or they may select not to include use cases for AMI in early program designs to reduce the complexity of performance payment calculations. Establishing new frameworks such as P4P can be difficult, and more complex design elements can be introduced over time if necessary. Further, leveraging AMI in support of P4P requires data access for program administrators like NYSERDA and DC SEU as well as the implementers or "aggregators" who run the program. In addition, it requires investment in staff capacity on procurement, contract structuring, and the other tools required to structure performance payments and create the platform for a P4P marketplace. Finally, fully leveraging this use case requires commitment from evaluators and utilities to use the data to optimize programs in real time.

MEASUREMENT AND VERIFICATION

AMI creates new opportunities for measurement and verification of energy savings from utility energy efficiency programs. Most past methods of M&V have relied on monthly use data, customer surveys, statistical modeling, and possibly some on-site metering (primarily for large commercial and industrial customers). The lag time of one to two years from the end of a program year in determining impacts can result in inefficiencies and higher costs because of the slow feedback and delayed ability to detect problems. By contrast, AMI yields near-real-time measurement of actual energy use. Program managers can use such timely and highly granular customer energy use data to monitor program results closely to assess ongoing performance, detect problems, and take corrective actions as indicated.[17]

The advent of AMI and related information and communication technologies has given rise to M&V 2.0, a major advance in how program managers and evaluators measure and verify energy savings.[18] NEEP (2016) views M&V 2.0 as the ability to use granular data, analytics, and computation on a large scale to streamline the M&V process. These advanced M&V methods hold great potential to determine energy savings in near real time to benefit stakeholders. LBNL researchers (Franconi et al. 2017) cite numerous benefits from these methods, including:

- More timely and detailed information on program results
- Ability to inform ongoing building operations
- Early input on energy efficiency program design
- Consistency and improved accuracy of impact measurement
- Ability to assess impacts by location and time of day
- Increased confidence in M&V results

AMI data enable program managers, implementers, and evaluators to gain a more comprehensive understanding of a program and measure impacts, particularly energy use at different times of the day. It also is important that all users of AMI employ common data platforms that provide secure nodes for accessing data and ensuring consistency. The more continuous M&V possible with AMI data and advanced, automated analytics can be used to spot problems more quickly and make any indicated changes to improve program performance. Another benefit of early feedback is the ability to identify which types of customers are achieving better measured performance. Such data can in turn be used to enhance program targeting—concentrating efforts on those customers most likely to benefit from certain measures. Programs can use performance dashboards that draw on AMI data to show program results in near real time.

Use of M&V 2.0 methods does not appear to be systematic for any utilities or states and did not come up as a use case in any of our utility interviews. However LBNL is working with states and utilities across the country to formally test the value proposition associated with

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[17] Granularity of data can take several forms. For AMI and related building data, these primarily are measurement interval, volume, and end-use detail.

[18] See also Nowak, Molina, and Kushler (2017) for a discussion of definitions, recent trends, challenges, and examples.

these tools. Pilots are being conducted with Sacramento Municipal Utilities District, multiple gas utilities in California, Eversource and United Illuminating in Connecticut, Seattle City Light and Bonneville Power in Washington State, and BC Hydro in British Columbia (Berkeley Lab 2019). These pilots are largely ongoing, with limited published results, and tend to focus on comparing M&V 2.0 tools with traditional M&V methods. Early results for most projects find a good fit to the model for a subset (~50–75%) of buildings, with uncertainty exceeding ASHRAE guidelines in a significant number of buildings.[19] LBNL tends to find the most value in delivering early feedback on savings as they accrue and in identifying nonroutine events and underperforming projects (Berkeley Lab 2016b, 2016a; NEEP 2019). Efficiency Vermont is also testing the use of AMI data for M&V in a pilot comparing homes with energy efficiency measures against a control group. This effort will yield efficiency savings load shapes, hopefully with time-differentiated impact estimates for efficiency programs that can be used in valuing energy efficiency at different times of day and year (Fink 2017).

Utility System Efficiency (Including Conservation Voltage Reduction)

Much of the impetus for AMI is improving and optimizing grid or system efficiency. As discussed earlier, AMI can be coupled with pricing, incentives, and customer programs to modify system demands and reduce loads at the peak periods when meeting demand is expensive. By flattening demand through overall reductions or shifting loads from peak to off-peak periods, grid efficiency is improved and costs reduced.

AMI technologies can provide utility systems with data, control, and communication capabilities beyond customer power demand and energy use. One such capability is voltage monitoring, which measures voltage levels and some power quality parameters, enabling utilities to develop accurate voltage profiles across feeder lines. These profiles can be used to diagnose customer voltage issues remotely and to optimize voltage across the grid (DOE 2016).

This ability to monitor voltage can be used by system operators to implement CVR as a means to reduce distribution power losses. CVR involves measuring and analyzing voltages on distribution feeders in order to find ways to reduce voltages while still maintaining service requirements (including voltage and phase balance) at levels that allow equipment to operate without problems. Lower voltages can improve end-use equipment efficiency and reduce line losses on both the customer and the utility sides of the meter. Voltage optimization can also improve effective capacity (kW) and help with reactive power management (Schwartz 2010). The Central Lincoln People's Utility District in Oregon implemented a pilot CVR program that yielded a 2% energy savings for all customers (DOE 2016). On the basis of this result, the utility plans to implement the program system wide.

Dominion Energy offers another example of utility CVR. Since 2009 Dominion has installed more than 450,000 smart meters in its service areas in Virginia and North Carolina and has

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[19] AHSRAE Guideline 14, Measurement of Energy, Demand, and Water Savings, provides guidelines for minimum performance in reliably measuring the energy, demand, and water savings achieved in conservation projects.

used a subset of the information provided by these meters to implement CVR. Dominion has software that measures the energy savings from CVR, and the utility is now achieving an average of 2.9% savings year-round. Dominion has also been actively marketing voltage optimization services to other utilities, including PG&E, Hawaiian Electric, Nevada Power, Hydro Ottawa, and several municipal utilities. The company estimates savings on a circuit by alternately raising voltage and then restoring the voltage to normal and seeing how loads change in response. Savings vary from utility to utility and have ranged from 2–4%, with lower savings for circuits in the moderate climates along the Pacific Coast and higher savings higher in East Coast applications. The Potomac Electric Power Company (Pepco) provides another example of CVR energy savings. Pepco's impact analysis shows that a 1.5% voltage reduction on its Maryland distribution system provides an annual nonresidential energy reduction of 0.9%; for residential customers the savings are 1.4% (Sergici 2016).

Potential Energy Savings from AMI-Leveraged Energy Efficiency

As these cases demonstrate, AMI can be—and is—a powerful tool to help customers reduce their energy consumption and energy costs. As such, AMI also provides important benefits to grid operators, as discussed earlier. The energy savings possible through different uses of AMI to advance energy efficiency vary. Some have been well developed and documented; these include:

- Near-real-time and behavioral feedback: 1–8%[20]
- Pricing with time-varying rates: 1–7%
- Conservation voltage reduction: 1–4%

Other uses of AMI also have strong potential to improve energy efficiency programs and evaluation, contributing to and supporting customer savings. For program design, examples include the use of AMI data for customer targeting and recruitment. For program evaluation, AMI can provide accurate and timely data to facilitate P4P approaches, as well as allow rapid feedback to management for program improvement.

While AMI can be used as a tool for helping customers reduce energy use, as we have discussed, our research on past performance shows no obvious connection between performance in demand-side energy savings and penetration of AMI. There are leading utilities for customer energy efficiency programs with and without AMI. For example, Eversource MA and National Grid MA, which do not have AMI, held the top two spots in the 2017 *Utility Scorecard*, but in third and fourth place were utilities that do have AMI, PG&E and Baltimore Gas and Electric (BGE). Similar patterns exist throughout the spectrum of energy efficiency performance (Relf, Baatz, and Nowak 2017). Nonetheless, it is clear that many of these use cases are underexploited, and with better adoption and further evidence, a stronger statement may be possible about the relationship between AMI and energy savings. Further, as energy efficiency program delivery evolves as a climate and

[20] Feedback devices and programs show wide variation due to different designs, such as opt-in versus opt-out. See Sussman and Chikumbo (2016).

grid resource, the capabilities of AMI highlighted in these use cases will become increasingly valuable.

Barriers to Leveraging AMI to Save Energy

As illustrated above, AMI can yield significant potential utility and customer benefits, including energy savings and peak demand reduction. However our survey of the top 52 electric utilities by sales, as well as interviews across the industry, suggest that utilities are largely underutilizing this resource. Our interviews with program administrators and literature review further revealed common limiting factors for leveraging AMI.

There are myriad barriers to adoption of AMI in the first place, including the challenges of justifying these investments where AMR has already been deployed, issues with measuring some of the benefits of AMI, and communications challenges with regulators, consumer advocates, and customers (NEEP 2017). Unclear business cases for AMI adoption can lead to denial of AMI applications, as seen in recent rejections in Massachusetts, Kentucky, New Mexico, and Virginia. However this section highlights barriers to the use of these systems for utilities, regulators, and customers, as well as technological issues limiting their use by those groups.[21]

Utility

Utilities that do not perceive a need to know and understand their customers are less likely to implement programs that leverage AMI; unfortunately, our interviewees found this blind spot prevalent across the industry. When utilities neglect to do customer research using AMI, they miss out on the benefits of customer targeting, feedback, and more robust M&V. This barrier is driven by a few challenges. First, monopoly utilities with a guaranteed customer base may lack a core competency in customer acquisition and engagement, which may discourage some utilities from focusing on customer-facing offerings or using customer data to gain insights. Second, utility business models encourage utilities to focus on capital investments. Utilities may need to make up for lost revenues intended to cover fixed costs from reductions in sales through decoupling or lost revenue adjustment mechanisms (LRAM). They may also need additional earnings opportunities to make up for avoided capital investments due to lower sales and peak demand levels through performance incentive mechanisms.[22] Last, utilities are often reluctant to share data with nonutility vendors that offer additional services and products because these services and products may not offer value to their utility business model. Even where utilities are willing to share data, they may lack clear ownership and access policies around data collection, data storage, and customer data access portals.

In our literature review we found limited evidence for direct energy efficiency savings from AMI outside of feedback augmented by behavioral energy efficiency and demand response or automation technology, pricing, and CVR; many of the promising use cases were

[21] We have outlined customer barriers here regardless of particular customer characteristics; however it is important to note that barriers may differ across the spectrum of customer segments.

[22] For more information on utility business model tools such as decoupling, LRAM, and performance incentives and how they encourage energy efficiency investment, see Molina and Kushler 2015.

enabling or indirect in nature, and many had limited examples. The lack of concrete evidence for savings directly stemming from AMI can make it difficult for utilities to build a good case for AMI deployment. Utilities rarely prioritize testing the success of measures or programs with and without AMI, so it is difficult to isolate the incremental value of AMI use cases. Further, regulators rarely require such detailed demonstration of benefits. Nonetheless, behavioral program vendors noted in interviews that where utilities have access to AMI, they typically do use it to provide more relevant insights to customers.

AMI deployments require utility investment and workforce development to implement the new technology, and this can challenge utilities without such infrastructure and workforce. Utilities should allow "sufficient time to plan AMI deployments including logistics, asset management, records management, workforce management, and integration with communications, MDMS, OMS, and other affected systems" (DOE 2016). When AMI is in place, utilities may have to hire staff with new skills or train existing staff in data science, marketing, communications, customer service, and engineering to incorporate these data into their work flow. According to a DOE case study, PECO invested time to coordinate internal and external communication systems and processes to aid workforce development and customer communication for their AMI deployment. Internally they "held regular meetings, developed standard messaging, and implemented a dedicated intranet page to help with workforce management and training" (DOE 2016). PECO also created uniform talking points, presentations, and other materials to share with the public and local media (DOE 2016).

Regulatory

AMI produces a much higher volume of customer data than traditional analog meters. Having additional data creates opportunities for energy savings but also raises data privacy and cybersecurity concerns. "AMI deployments raise new questions about the security of customer data, the types of entities that can access it, and how the data will be protected from cybersecurity breaches and other data privacy intrusions" (DOE 2016). Thus, standards, tools, and other techniques are needed to ensure that data privacy and cybersecurity are not compromised. Our interviewees stated that there is technology to support cybersecurity and privacy, but utilities and states struggle to create and apply clear rules that allow customers to easily access their data and vendors to provide energy services. Green Button is one such set of standards, although application can be inconsistent (AEE 2017a).[23] An additional challenge in creating these rules is consumer advocates' resistance to approving AMI programs or third-party access to data (Chris Villarreal, president, Plugged In Strategies, pers. comm., July 12, 2019).

AMI requires significant investment of ratepayer dollars. In most states, utilities request pre-authorization of these expenses, and consumer advocates and some regulators balk at the potential ratepayer impacts, especially where there are insufficiently beneficial business cases. Primary hesitations tend to consist of concerns about delivering uncertain benefits

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[23] Green Button comes in two forms: Green Button Download My Data, which allows customers to download their energy use data and upload it to a third-party application, and Green Button Connect My Data, which enables customers to automate the secure transfer of their usage data to third parties.

relative to costs and concerns about equity and uneven distributional impacts. However there are notable exceptions. For example, the Illinois Citizens Utility Board has supported AMI rollout and has endeavored to ensure that the AMI offered to Ameren and ComEd customers is used in service of energy savings, including by conducting research tracking the impact of real-time pricing across customer classes (Thill 2019).

Technology

Utility systems designed for small volumes of monthly data and systems without necessary integration can limit the potential of AMI data. To fully take advantage of large interval load data sets produced by AMI, utilities need to improve data processing and management, models for assessing system conditions and predicting demand impacts and energy savings, and some software platforms (DOE 2016). Many of these data processing capabilities are delivered through service-based solutions, which are often lower cost and cloud based. Utilities typically have a disincentive to use such resources, as they are usually not valued as an asset; using their own capital resources could artificially raise the cost of AMI deployment.[24] More-advanced analysis strategies and software platforms will allow utilities to effectively utilize AMI data for multiple use cases such as creating more time-varying rates, customer targeting, meter-based P4P tracking, and planning.

Another technology gap stems from utility reluctance to adhere to consistent data formats and transmission protocols, such as Green Button Connect My Data, and to adopt comprehensive interoperability standards to support connections among smart meters, customer devices, and communications and information systems (DOE 2016). This creates a barrier for third-party data sharing. Continued advancements in mobile apps are also needed to share real-time data and energy usage insights with customers (DOE 2016). There are limited examples of utilities using such applications.

Customer

Families and businesses themselves are key actors in leveraging AMI to save energy on their bills; most energy savings require some action by customers, such as responding to a rate, purchasing energy efficiency equipment or services, or setting up automated devices. Barriers for customers include lack of engagement, interest, or motivation. Customers need access to educational materials and support services to understand program structure and elements and how to save energy and earn rewards. Customers also need personal energy usage insights delivered to them in an accessible and timely manner. Personalized insights and tips for energy usage reduction, delivered within 24 hours of an energy savings event through the customer's preferred mode of communication (e.g., phone call, text, e-mail, or mobile application), can motivate customers to save energy more than impersonal, delayed information.

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[24] Exceptions are found in New York, which allows a rate of return for prepaid software services, and Illinois, which is considering extending the potential opportunity to earn a partial rate of return to pay-as-you go services.

Practices to Leverage AMI to Save Energy

Leveraging AMI to save energy requires action from utilities in their roles as energy efficiency program administrators, grid planners, and grid operators. They are also the primary entities identifying AMI technologies, selecting vendors, and investing in these resources on behalf of the system and their shareholders. State utility regulators review the prudence of AMI investments, provide oversight to determine whether to allow expenses or incentives associated with these investment, and in limited instances set performance standards for AMI investments. The ecosystem of third parties can provide critical services that leverage AMI in data science, customer segmentation, customer marketing and program implementation, and resource aggregation to meet planning needs. Of course, customers too have a key role to play, as many of the use cases for AMI to save energy require their initial investment or continued participation.

Below, we outline the practices our research found among utilities and regulators that can ensure successful deployments that leverage AMI for customer energy savings, including some practices that address the barriers outlined above.

UTILITIES AND PROGRAM ADMINISTRATORS

Implementation of AMI by a utility is much more complicated than simply changing out meters. Effective deployment and use of AMI require coordination across multiple departments or units within the typical utility structure, including:

- *Information technology and accounting*. Data management, recordkeeping, and customer billing
- *Planning*. Customer and load data for forecasting
- *System operations*. Monitoring and managing system resources to meet loads
- *Marketing/communications*. Educating and informing customers about AMI
- *Customer service* (including programs for energy efficiency, demand response, and DER). Using AMI capabilities to help customers change behavior and take other actions to reduce or shift energy use to lower their energy costs
- *Regulatory affairs*. Gaining approval needed by regulators to adopt AMI
- *Rate design*. Exploiting new opportunities to create time-varying rates

Utilities and program administrators need to break down traditional silos that contain these various functions in order to manage and use AMI to its fullest capabilities to benefit customers and system operations. That includes investing time to coordinate internal and external communication systems and processes, as PECO did for its initial communications rollout for AMI, and as PGE continues to do in its efforts to leverage multiple use cases of AMI.

The highly granular data that AMI provides are beneficial only if they can be effectively managed, analyzed, and used to inform and motivate customers to take actions to achieve desired outcomes. Utilities and program administrators need to invest in data scientist capacity accordingly, bolstering capabilities such as big data management, analytics, security, and communications. AEE (2017) stresses the need for utilities to invest in back office and data management systems to allow customers full access to their data in a form that is easy to understand and identifies opportunities for beneficial changes. AMI data also need to be readily available not just to customer billing and records departments, but also to demand-side management program staff, system planners, and system operators. Utilities should engage the range of actors within and outside the utility who might identify use cases for the data, create systems for those who will be handling and entering it, and establish guidelines for accessing and interpreting it (e.g., definitions for each entity in the data warehouse).

Some early experiences with utility rollout of AMI demonstrate the need for effective communications. Moving from traditional, manually read meters to billing based on AMI is a large change for customers. Without effective communications, customers may resist the changes out of concerns about data privacy, security, or increased costs. Utilities need to build strong business cases for AMI that clearly show how customers will benefit. They also need to provide the tools and services necessary to enable customers to take advantage of AMI and realize its benefits. Utilities should tell the story of what steps are needed to save money from the capabilities of AMI and associated pricing or incentives.

An effective approach for rollout of AMI with time-varying pricing is to make participation opt-out as opposed to opt-in. Investor-owned utilities in California are taking this approach for time-of-use rates, as are leading municipal utilities such as SMUD (DOE 2016) and Fort Collins Utilities (DOE 2013).[25] BGE has successfully combined opt-out peak-time rebates with behavioral demand response in its Smart Energy Rewards program. The program has more than 1.1 million customers enrolled—a result that BGE achieved by registering customers automatically when AMI meters were installed. Customers can opt out, but the large majority have not done so; 70% have participated since 2015 (BGE 2019). This program is not focused on energy efficiency but has delivered 1,280 MW in peak demand savings across five summers between 2013 and 2017 (AEE Institute 2018). The 2018 forecasted annualized energy savings for the Smart Energy Rewards program is 4,719 MWh. Additionally, $16,064,171 in total bill credits were paid to customers (BGE 2019).[26]

A more typical approach to rollouts of TOU pricing with AMI is to have customers opt in. Such an approach generally yields much lower participation, although participants are often more engaged. SMUD conducted pilot programs to test different approaches to introducing TOU rates, using both opt-in and opt-out designs. SMUD's evaluation of these pilots found higher enrollment rates for opt-out approaches without significant differences in dropout

[25] Fort Collins Utilities technically did not offer opt-out; rather it offered options to customers with a standard AMI rollout that would address their privacy or other concerns. One option was to reprogram the AMI to not collect interval data (a single electric data point/day); the other option was to record interval data but not transmit it via radio broadcast, thus necessitating manual meter reading at an additional cost of $11/month.

[26] Customers earn $1.25 per kWh saved during an Energy Savings Day between 1 p.m. and 7 p.m. during the control season. Energy reductions are measured against a baseline determined by a customer's average energy usage for nonevent days with similar temperature and humidity conditions (AEE Institute 2018).

rates or peak demand reductions.[27] Benefit–cost analysis of these pilots revealed greater net benefits and more favorable business cases for opt-out than for opt-in (DOE 2016).

REGULATORS

Regulators can align the behavior of monopoly firms (their investment in AMI) with the public interest (the potential benefits of AMI, including saving energy) by setting performance standards for utilities and then enforcing them with positive and negative consequences (Hempling 2013). In the case of smart grid deployment, regulators must first assess the costs and benefits of smart grid investments relative to their affordability, safety, and reliability and to environmental and other performance standards. This includes quantifying and incorporating the benefits from saving energy into regulatory proposals. Some utility applications fail to include a cost–benefit analysis in their business case; regulators can require such an analysis to support their decision making.[28] They must then monitor performance to ensure that those benefits are delivered, using the tools available to them, including mandates for specific actions and adjustments to compensation. Finally, regulators can set standards and oversee investments in a way that encourages utilities to innovate on behalf of ratepayers.

Quantifying and Incorporating Benefits from Saving Energy in Business Cases

As early as 2009, the National Association of Regulatory Utility Commissioners (NARUC) issued a resolution on smart grids calling on member commissions to ensure that any smart grid technology deployment plans continue to be subject to record-based reviews. These reviews should "ensure proposals—and in particular the utility's proposal for recovery of its capital outlays—are both cost-effective and actually result in benefits to ratepayers" (NARUC 2010).

Regulators, coop boards, and municipal oversight bodies have reviewed such plans since 2009, choosing to approve tens of millions of meters in dozens of AMI proposals but also rejecting some notable ones. As these oversight bodies review AMI proposals, they should use a robust cost-effectiveness framework that considers the role of customer benefits, including customer energy efficiency, in justifying the utility investment. The Electric Power Research Institute (EPRI) offers one such framework, which evaluates a range of benefits including customer and environmental ones, and which was used by PG&E and San Diego Gas & Electric in California in their proposals (EPRI 2010). The EPRI framework includes key benefits from energy savings, including avoided energy costs, energy procurement, and price mitigation. Including these can help properly value investments in AMI and can help motivate regulators to put in place metrics or requirements that these savings materialize.

Where those customer benefits are core to the business case, utility proposals should clearly outline how they will achieve those benefits, and approval of investments should be contingent on inclusion of an adequate plan for how new capabilities will be used to advance energy efficiency. Proposals should include any complementary investments on the

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[27] See Cappers et al. 2016 for more information and analysis of default designs for rate structures.

[28] For example, Indiana Michigan Power in Michigan filed their rate case in May 2019, including a request for cost recovery of their AMI investment. They did not include a cost–benefit analysis in that filing (Case U-20359).

utility back end or in customer communications, which would be necessary to realize those customer benefits. For example, the communications capabilities of AMI should be able to send pricing or load control signals through the meter to devices in the home if demand response programs are envisioned as a use case for AMI. Similarly, billing systems must be capable of integrating the rates into customers' bills.

Adjusting Shareholder Compensation for AMI Investment Based on Performance

In addition to approval of new technology needs, regulators and other oversight bodies determine whether and to what extent ratepayer funding can be spent in support of those investments. As they review AMI proposals, states apply different levels of scrutiny, which may or may not include a societal perspective depending on which cost-effectiveness test is used (NEEP 2017). State regulators have a range of financial options for encouraging utilities to deliver on expected benefits from AMI, including energy savings and customer benefits. These include performance-based regulation to align investments with desired outcomes, making additional earnings from AMI conditioned on realization of claimed benefits. Regulators can also consider delay or denial of some compensation to shareholders when benefits are not delivered, such as when a program fails to produce a reduction in the authorized revenue requirement that was expected due to projected operational savings from AMI.[29] However there is a risk that this will chill investment, as local distribution companies will be less likely to invest where cost recovery is uncertain or not timely or where regulators place conditions on recovery.

Maryland regulators successfully tied shareholder compensation to delivery of expected benefits in an early AMI deployment. BGE's initial petition to deploy AMI (Case 9208) was rejected in 2009 due to concerns about the cost–benefit analysis. The utility resubmitted the application with an updated business case, including a consumer education and communication plan to better support energy conservation (NEEP 2017). Although BGE was granted approval for the deployment, cost recovery in base rates was deferred until the investments proved cost beneficial. In response, BGE deployed one of the most successful behavioral demand response and peak-time rebate programs in the country, Smart Energy Rewards, described in the Practices to Leverage AMI section below.

Regulators can also use performance-based regulation (PBR), especially performance incentive mechanisms (PIMs), to tie compensation to desired policy outcomes rather than spending. PIMs are commonly used for energy efficiency programs, but an increasing number of states are looking to these mechanisms to encourage outcomes such as reliability, peak demand reduction, greenhouse gas reduction, beneficial electrification, and targeted DER deployment.

The Regulatory Assistance Project (RAP) recommends consideration of PBR methods to advance two desired outcomes: delivering investments on budget and completing their deployment on time. For example, French regulators used PBR in the smart-grid rollout of Électricité Réseau Distribution France (ERDF), a distribution system operator. They used

[29] There are numerous cases, such as in Washington, Massachusetts, and Pennsylvania, where regulators have disallowed full recovery of undepreciated assets to protect ratepayer interests (Peskoe 2016).

metrics around cost controls, deployment timing, and system performance when installed, as well as metrics to measure whether operational improvements, such as reduced line losses and meter reading, were actually occurring (Littell et al. 2019). RAP notes the potential for gaming risk with PBR, and suggests using benchmarking, rules around including costs in rate base only when "used and useful," and careful review of timelines and budgets to mitigate that risk.[30]

We are not aware of any PIMs associated with *leveraging* AMI, where PIMs are specifically focused on measuring service results, such as energy or demand savings outcomes from these investments. Littell, Shipley, and O'Reilly (2019) offer multiple examples of potential goals and outcomes for AMI. We reproduce in table 4 their examples that are potentially relevant to the energy savings use cases described in this work. Regulators could also consider metrics to encourage outcomes from use cases like targeting and technical assistance or from grid-interactive efficient buildings, measured in program adoption or the value of grid services procured through GEBs.

Goal	Outcome	Performance criterion/functionality	Metrics to track
Feedback. Customer understanding of energy use	Higher customer satisfaction or understanding of energy use	Operation of customer energy usage portal	Customer usage of energy portal; one-time or regular access
Pricing. Vibrant real-time or TOU energy market for residential users	Customer costs more reflective of system costs; efficient pricing	Customer on a real-time or time-varying rate plan	# and % of customers opting out of or taking price offering
Data access. Authorized access to customer data by third-party energy providers	Utility supports system for customers to share data with third parties	Third-party energy service company ability to access Green Button data	Number of third parties that successfully access customer data through Green Button Connect or other utility data-sharing method; % of customers able to authorize third-party service company requests on first attempt (target: 95%); % of time third-party service provider receives access when authorized by customers (target: 95%)

Table 4. Goals, outcomes, and performance criteria and metrics associated with AMI deployment. ***Source:*** **Littell, Shipley, and O'Reilly 2019.**

Although we have yet to see the emergence of PIMs for leveraging AMI to advance energy efficiency, some of the customer engagement metrics proposed as earning adjustment mechanisms in New York's Reforming the Energy Vision proceeding could be relevant. These included metrics that measure increased customer engagement

[30] "Used and useful" is a standard for assets that are required and that operate in an effective and efficient manner (CPUC 2017).

through online portals, use of utility-provided data feeds, and use of download options, and metrics that measure the prevalence of customer-oriented products that use AMI data (New York PSC 2016).

Setting Performance Standards for Data Access and Energy Savings

Although there are operational benefits that accrue immediately upon deployment of AMI, most customer-focused benefits require further actions by utility regulators. In such areas as energy savings and data access, regulators can directly set standards for expected utility performance associated with AMI rollouts.

Despite the potential for energy savings and the limited application of AMI as a tool to support energy savings across US utilities, we saw few examples of state regulators requiring utilities to verify that they delivered peak kW or seasonal or annual kWh savings from AMI investments. Southern California Gas (SoCalGas) is a notable exception. In its 2010 approval of the utility's AMI proposal, the California Public Utilities Commission required that SoCalGas set a goal to save 1% of residential gas usage and that it track and attribute the conservation impacts of the AMI rollout, reporting every six months from August 2013 to February 2018 (CPUC 2010). The utility met this requirement through a combination of seasonal home energy reports targeted at winter heating and particularly cold-weather-sensitive customers, weekly "bill tracker alerts," and standard home energy reports (Schellenberg 2017). As shown in figure 6, the utility tested a wide variety of combinations, with successful results (greater than 1.0% savings) in some of the tests in the first two years of the program and savings greater than 1.4% in the last two program years (SoCalGas 2018). While the highest savings rates were beyond typical gas savings from home energy report programs, the average savings were close to typical. This suggests strong impacts for some individuals from the season-specific and end-use-specific messaging that required AMI data, but average savings overall, consistent with the discussion of feedback above.

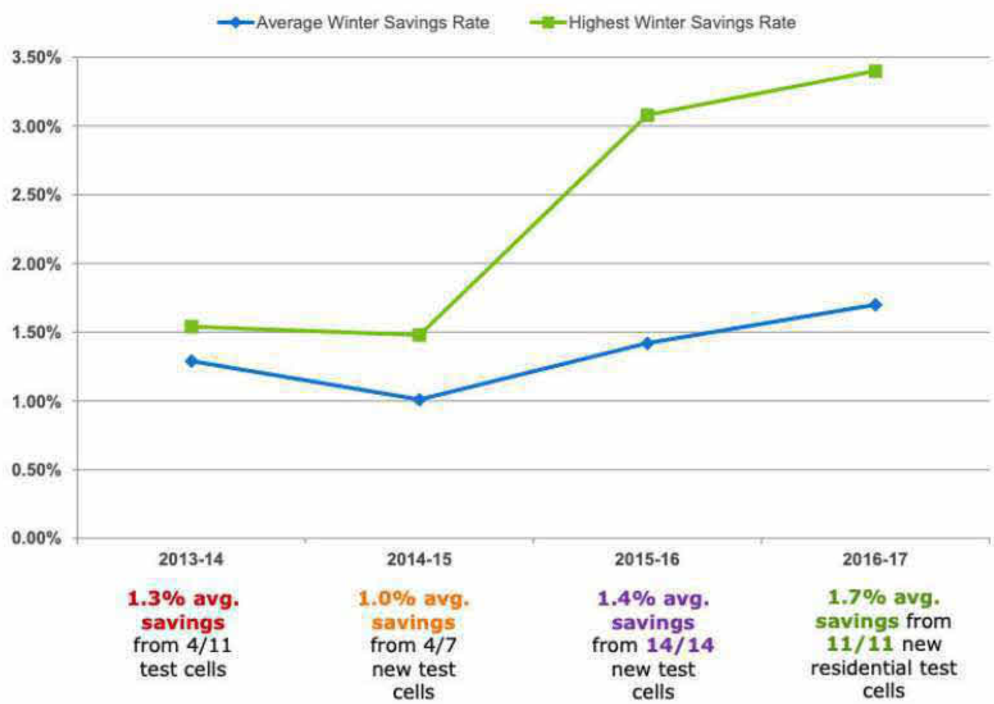

Figure 6. Average household savings from test cells in SoCalGas heating season–focused behavioral programs from 2013–2014 to 2016–2017 program years. *Source:* Schellenberg 2017.

Another form of performance standards are data access and customer privacy protections, which are critical to ensure that customers realize energy savings benefits from AMI. Customers and their third parties must be able to gain access to data in a timely fashion.

ACEEE's *State Scorecard* offers a road map for regulators to follow to enable interval data access, building on a framework created by Mission:data (Murray, Kier, and King 2017). First, regulators can require utilities to provide energy usage data to customers in a standardized electronic format, like Green Button Connect. Only six states have done so as of 2019 (Berg et al. 2019). Second, regulators can ensure that third parties have access to data by providing guidelines for how customers can share access. Sixteen states have such guidelines, and ten states require provision of individual energy usage data to third parties upon customer authorization (Berg et al. 2019). Finally, regulators can require that utilities provide aggregated data to owners of separately metered commercial or multifamily properties and public agencies, enabling benchmarking and identification of opportunities for energy efficiency improvements. Four states have such a requirement for multi-tenant building owners, and eight require utilities to provide this data to public agencies (Berg et al. 2019).

Encouraging Innovation to Leverage AMI

Much of the potential value from AMI derives from differences in the time and locational value of energy savings on the grid. Regulators will need to ensure that valuation and transaction mechanisms are available to unlock that value while protecting vulnerable customers.

Time-varying pricing can enhance the value of energy efficiency and peak demand reductions (Baatz 2017), enabling demand-side resources to lower system costs and customer bills. States without time-varying rates can leverage lessons learned from other states, focusing on designs that limit peak period duration and critical peak pricing period frequency, and coupling rates with communications that support responsive decisions and with technologies that automate customer response, such as programmable thermostats (Sherwood et al. 2016). Such rates primarily deliver peak demand reductions and system efficiency but also support some energy savings. Where utilities lack experience with such pricing, regulators can encourage or require pilots with defined plans for scaling based on lessons learned.

Similarly, regulators can use pilots and innovation plans to encourage utilities to test other use cases that leverage AMI, including targeting and segmentation, new ways of providing feedback, P4P, and grid-interactive efficient buildings. They can also pilot new M&V approaches alongside existing methods to understand their impact before rolling them out as the default method. These pilots can help address utilities' risk aversion and reluctance to innovate without preapproval (Fairbrother et al. 2017).

Conclusions and Recommendations

Technological advancements and market developments have fueled the rapid growth of AMI since the early 2000s. It is the foundation of the grid modernization needed to replace aging infrastructure and integrate DERs. The business case for AMI has relied primarily on operational benefits for utilities, which include:

- Reduced metering and billing costs
- Enhanced ability to detect, isolate, and respond quickly to outages
- Improved safety

The granular interval data provided by AMI also offer many potential advantages to energy efficiency, demand response, and bill management benefits for customers. AMI data can help utilities and third parties create better, more compelling, more cost-effective energy efficiency offerings by:

- Enhancing the quality of and insights from near-real-time feedback on energy consumption and using AMI data for behavioral feedback
- Providing time-varying pricing that reflects varying energy costs at different times of day and year. Near-real-time feedback, combined with communications and possible automation, can better inform and motivate customers to respond to pricing signals and change their energy use accordingly.
- Targeting energy efficiency and other demand-side programs, incentives, and services to those customers most likely to benefit from them
- Improved M&V, to support greater accuracy in impact estimates and more continuous learning through near-real-time feedback to program managers
- Promoting grid-interactive, efficient buildings that extract more grid value from customer programs by providing more flexible demand

- Supporting energy procurement and meter-based pay-for-performance programs that better align outcomes, address siloing between resources, and support acquisition of energy efficiency and other demand-side options as a resource
- Enabling conservation voltage reduction on electricity distribution networks to reduce demand and energy use

We find that many utilities are underexploiting AMI capabilities and its attendant benefits, thus missing out on a key tool to deliver value to their customers and systems. In particular, they underutilize AMI's ability to support customer energy efficiency through information, pricing, and technical assistance insights, and its ability to improve program design through targeting, P4P, and more robust evaluation. When they neglect to use AMI data, they also largely undervalue the potential grid benefits from efficiency programs in grid-interactive efficient buildings.

Some of AMI's benefits can be provided by other technologies like building energy management systems, home energy managements systems, smart thermostats, and other ownership models besides utility deployment. However only AMI appears to be capable of delivering all the use cases outlined for energy efficiency.

Utilities can learn from the experiences of other utilities in rolling out AMI and associated pricing and customer programs. One key to successful rollouts is customer engagement, beginning with market research, stakeholder and community outreach, and customer targeting. Continued engagement efforts include providing customers with education, accessible support, and personalized energy usage insights. Utilities need to clearly demonstrate and articulate AMI's benefits for their customers' energy use. They need to build a strong business case for both customers and regulators that tells a clear story about how AMI will be used to deliver customer benefits, including energy savings.

Another key to gaining the greatest benefits from AMI is to couple it with well-designed, customer-friendly time-varying pricing, including meaningful marketing and education for those rates. This structure gives customers the best opportunity to reduce costs by modifying their energy use. Time-varying pricing is also critical for grid flexibility; it sends appropriate price signals to customers about system costs at different times. These signals enable them to shape and shift load to optimize grid performance and reduce system costs.

AMI also can enable conservation voltage reduction as a means to reduce distribution power losses. The few successful examples of CVR demonstrate its effectiveness. We encourage greater use of this capability of AMI.

As utilities develop and implement AMI, they also need to include complementary investments to realize the full spectrum of customer and grid benefits. This may involve acquiring new areas of expertise, whether by internal staffing or contracting with qualified, experienced vendors. Key functions include data management and system integration.

Successfully leveraging AMI to advance energy efficiency also requires supportive regulation. Regulators should:

- Ensure that proposals by utilities for implementing AMI include and accurately quantify a full set of customer benefits, including saving energy and reducing costs
- Require utilities to demonstrate how they use AMI technology to help achieve customer energy efficiency
- Require that AMI cost recovery be contingent on delivery of benefits claimed in proposals.
- Create performance incentives or other mechanisms to align spending with desired outcomes, including energy savings, or processes, such as data access or use of AMI data for program design
- Support and approve time-varying pricing, such as TOU rates, in concert with AMI rollouts.
- Set standards or requirements to deliver the expected savings or other benefits from AMI
- Establish clear data access rules that ensure data security and provide options for customers, third parties, and residents in buildings served by multiple meters, such as many multifamily buildings
- Allow for pilots and innovation activities designed to test and scale applications that leverage AMI data for customers, the market, or the utility
- Encourage utilities to implement CVR as part of their AMI rollouts.

Rollouts are premised on the ability of this technology and associated systems to deliver benefits to customers and utilities, not the least of which is saving energy. To achieve this result, however, takes more than simply giving customers more detailed energy use data. Utilities must actively engage with their customers and offer them a range of services to support their energy savings investments and actions, such as behavioral feedback.

AMI is considered by many to be a foundation of grid modernization and all its many benefits to customers, grid operators, and resource providers. One such benefit that is currently underutilized is reducing energy use through increased energy efficiency of customer end uses and the distribution network. To realize this benefit, utilities need to fully leverage AMI as a powerful tool toward the many uses and applications for energy efficiency that can be advanced by AMI's data and communications capabilities.

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Appendix A. Interviewees

We interviewed each of the individuals below to gain background knowledge and confirmation of our primary desktop research. We gratefully acknowledge their contributions and note that these interviews do not imply affiliation or endorsement.

General Expertise

Advanced Energy Economy, Ryan Katofsky

US Department of Energy, Buildings Technology Office, Monica Neukomm, Johanna Zetterberg, Steve Dunn, Amy Jiron

Edison Electric Institute, Adam Cooper

Lawrence Berkeley National Laboratory, Peter Cappers, Annika Todd

Mission:data, Michael Murray

Plugged In Strategies, Chris Villarreal

Smart Energy Consumer Collaborative, Patty Durand, Nathan Shannon

Service Providers

Copper Labs, Dan Forman

Opower, Oracle, Marisa Uchin and JD Toppin

Recurve, Carmen Best

Uplight, Monty Prekeris and Bryan Dreller

Utilities and Program Administrators

Baltimore Gas and Electric, Leigh Jarosinski

Detroit Edison, Joel Miller

NYSERDA, Megan Fisher and Kyle Monsees

PECO, Mike O'Leary and Jeff Myers

PGE, Erik Cederberg and Kirk Page

VEIC, Dan Fredman

Appendix B. Use Case Definitions

Table B1 details use case definitions from the survey of electric utilities we used in this report and from the *2020 Utility Energy Efficiency Scorecard*. These descriptions represent publicly available data and program information from 2018, largely based on 2018 regulatory filings, 2018–2020 planning documents, and additional filings on utility and public utility commission websites. For utilities that do not operate on the calendar year, we used data from the 2017–2018 program year.

Table B1. Use case definitions

Program measure	Description
Energy use feedback to consumers in real time	Allowing consumers to better understand their behavior and adjust their energy usage to increase savings. Includes programs that provide feedback in near real time. Typically requires advanced metering infrastructure (AMI) installation.
Behavior-based feedback	Reducing energy consumption through social science theories of behavior change by providing information to customers, by leveraging interpersonal interactions, or by providing consumer education. Excludes programs that rely on traditional program strategies such as incentives, rebates, or regulations.
CVR or VVO	Improving the efficiency of a utility's transmission and distribution system through voltage reduction systems, whether explicitly included in the utility's energy efficiency portfolio or not.
TOU rates	Charging different prices for electricity during different times of the day and year.
GEBs	Incentivizing buildings that reduce energy waste and carbon emissions while offering flexible building loads to the grid. This may include integrating energy efficiency and demand response to better value the many benefits of grid-interactive efficient buildings.
Data disaggregation	Extracting end-use-level and/or appliance-level data from an aggregate or whole building energy signal to engage consumers and to target relevant programs to specific customers.

Source: ACEEE survey of top 52 electric utilities' energy efficiency offerings and performance in 2018

Attachment CR-3

Public Discovery Responses

APS Responses to Data Requests

1. APS Response to SC DR 4.1
2. APS Response to SC DR 4.2
3. APS Response to SC DR 4.3
4. APS Responses to SC DR 4.4
5. APS Response to SC DR 4.6
6. APS Response to SC DR 4.7
7. APS Response to SC DR 4.9
8. APS Response to SC DR 5.1
9. APS Response to SC DR 5.4

SIERRA CLUB'S FOURTH SET OF DATA REQUESTS TO ARIZONA PUBLIC SERVICE COMPANY REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-19-0236
JUNE 9, 2020

Sierra Club 4.1: In 2018, APS reported on Form EIA-861 or EIA-861S that it has installed 1,264,448 meters of which 1,251,355 constituted Advanced Metering Infrastructure.
https://www.eia.gov/electricity/data/eia861/

a) Is this information still current? If not, how many total customers have advanced metering infrastructure?

b) How many residential customers have advanced meters?

Response:

a) As of May 31, 2020, APS had a total of 1,431,985 meters installed. Of those, 1,418,282 are AMI meters. Of these, 1,286,237 are billing meters and 132,045 are solar production meters (non-billing).

b) The Company has deployed 1,125,293 residential AMI billing meters.

Witness: TBD

SIERRA CLUB'S FOURTH SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO
DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-19-0236
JUNE 9, 2020

Sierra Club 4.2: In response to Staff Set 11 Question 1, APS provided an Excel spreadsheet which stated 698,368 customers have registered on the APS website.

a) Is it accurate to state that 55% of APS customers have registered for the APS website? If not, what percentage of APS customers have registered for the APS website?

b) Please provide the number of residential customers who have logged into the APS website at any time in 2019. Please provide the data as unique residential customers, rather than total site visits by residential customers. If the data requested are not available, please provide the data that most closely matches that requested.

c) Please provide the number and percentage of residential customers who have viewed their hourly energy usage data on the APS website at any time in 2019. Please provide the data as unique residential customers, rather than total site visits by residential customers. If the data requested are not available, please provide the data that most closely matches that requested.

Response: a) Please see below for the percentage of customers that have registered on aps.com.

Current:

Residential – 721,027 / 1,145,039 (customer count) 62.9%
Commercial – 34,427 / 136,126 (customer count) 25%

2019:

Residential – 700,803 / 1,135,033 (customer count) 61.7%
Commercial – 33,338 / 136,414 (customer count) 24.4%

b) There were 604,202 unique customer usernames that logged into aps.com from January 1, 2019 – September 28, 2019. This number includes both residential and commercial customers.

There were 1,420,625 customer logins from January 21 – May 8, 2020.

The way logins are measured changed with the introduction of the new website (launched on September 28, 2019). Instead of counting the username once regardless of how many times a customer logged in, aps.com now counts total logins. This accounts

Response to SC 4.2 (continued):	for the discrepancy in numbers across the timeframes stated. c) The requested data is not available. In 2019, there were roughly 52,667 residential customers on average per month who view their usage analytics page on aps.com. The current year to date (January – May 2020) monthly average is 45,200 residential customers. To be more specific, there were 401,243 visits by residential customers to the usage analytics page from September 30, 2019 – June 8, 2020.

Sierra Club 4.3: Of the total AMI meters, how many have the capability of reporting energy usage in increments of:

a) 1 minute

b) 5 minutes

c) 15 minutes

d) Hourly

Response:

a) APS currently has 317,141 meters capable of being programmed to supply one-minute interval data. However, additional communications infrastructure would be needed to send the data to APS if a smaller time increment than 15 minutes was programmed into the meter.

b) The 317,141 meters mentioned in subpart a could also be programmed to supply five-minute interval data. Additional communications equipment would also be necessary for this increment of data.

c) In addition to the 317,141 meters mentioned in parts a and b that could be programmed to record 15-minute interval data, APS also has 160,944 interval meters for commercial and industrial customers that are currently configured to record data in 15-minute increments.

d) The 1,125,293 residential billing meters referenced in Sierra Club Data Request 4.1 record usage in 60-minute intervals.

Witness: TBD

SIERRA CLUB'S FOURTH SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO
DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-19-0236
JUNE 9, 2020

Sierra Club 4.4: Of the residential AMI meters, how many have the capability of reporting energy usage in increments of:

a) 1 minute

b) 5 minutes

c) 15 minutes

d) Hourly

Response:

a) APS has 290,618 residential billing meters that could be configured to supply one-minute, five-minute, or 15-minute interval data. Additional communications equipment would have to be installed in order to send the data to APS.

b) Please see the Company's response to part a.

c) Please see the Company's response to part a.

d) All residential AMI meters (1,125,293) record usage data in 60-minute intervals.

Witness: TBD

SIERRA CLUB'S FOURTH SET OF DATA REQUESTS TO ARIZONA PUBLIC SERVICE COMPANY REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-19-0236
JUNE 9, 2020

Sierra Club 4.6: Is the energy data provided to customers via the APS website provided in Extensible Markup Language (.XML)?

a) If not, in what format is the energy data provided?

b) If not, do APS customers have any means to obtain their energy data in .XML format?

Response: a) Excel.

b) No, not at this time.

Witness: TBD

SIERRA CLUB'S FOURTH SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO
DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-19-0236
JUNE 9, 2020

Sierra Club 4.7:	Does the energy data provided to customers via the APS website comply with Green Button Download My Data standards? If not, in what way is it noncompliant?
Response:	The website does not currently incorporate the voluntary Green Button standards, most notably XML delivery consistency and data sharing authorization.

Witness: TBD

SIERRA CLUB'S FOURTH SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO
DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-19-0236
JUNE 9, 2020

Sierra Club 4.9:	Please provide the number of residential customers who have shared their data with a third party in 2019.
Response:	APS does not have information about how customers may use or share their own usage data.

Witness: TBD

SIERRA CLUB'S FIFTH SET OF DATA REQUESTS TO ARIZONA PUBLIC SERVICE COMPANY REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN DOCKET NO. E-01345A-19-0236 JULY 1, 2020

Sierra Club 5.1:

In response to Sierra Club 4.3(a) and 4.3(b), APS stated "However, additional communications infrastructure would be needed to send the data to APS if a smaller time increment than 15 minutes was programmed into the meter." Please provide the following information.

a. Does APS have plans to install the referenced "additional communications infrastructure" necessary to send energy usage data to APS in time increments less than 15 minutes?

i. If so, when?
ii. If not, why not?

b. Has APS evaluated the costs and benefits of installing the referenced "additional communications infrastructure"?

i. If APS has evaluated the costs and benefits, please provide a copy of such analysis including any work papers.
ii. If APS has not evaluated the costs and benefits, please explain why not.

c. Has APS considered any alternative to installing the additional communications infrastructure to provide the customer with energy usage data in smaller time increments than 15 minutes?

i. If so, what was evaluated? Please provide a copy of such analysis and any work papers.

d. If not, why not?

Response:

a. No.

i. N/A
ii. APS has not determined that the value of receiving the data in smaller time increments would offset the costs to implement.

b. No.

i. N/A
ii. APS has not determined that the value of receiving the data in smaller time increments would offset the costs

Sierra Club 5.1 Response (continued):

to implement.

c. No.

i. N/A

d. APS has not determined that the value of receiving the data in smaller time increments would offset the costs to implement.

SIERRA CLUB'S FIFTH SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO
DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-19-0236
JULY 1, 2020

Sierra Club 5.4: In response to Sierra Club 4.8, APS responded that a customer could share their energy data with a 3rd party by adding the 3rd party as a guest on their account. Please provide the following information.

a. Does the customer's guest have the same access to Energy Data that the customer has? If not, why not?

b. Does the customer's guest have access to Customer Account Data other than Energy Data? If so, what Customer Account Data can the guest access?

c. Can the customer's guest access information related to the customer's:

i. Social security number;
ii. State or federal issued identification number;
iii. Financial account number in combination with any security code providing access to the account;
iv. Consumer report information provided byEquifax, Experian, TransUnion, Social Intelligence or another consumer reporting agency;
v. Individually identifiable biometric data;
vi. First name (or initial) and last name in combination with any one of the following:

1. Date of birth
2. Mother's maiden name
3. Digitized or other electronic signature;

vii. DNA profile.

d. Can the customer authorize a time-limited guest access? If so, for what period of time?

e. How does the customer revoke a previously authorized guest access?

f. Does APS customer guest access comply with DataGuard Energy Data Privacy Program Voluntary Code of Conduct Final Concepts and Principles (Final, January 8, 2015)?

i. If not, how does it diverge?
ii. If not, why not?

Witness: TBD

Response: a. Yes.

b. Yes. What a guest can see and do is dependent on the type of access (permission) granted to the guest as outlined below. This information is available to all customers at: https://www.aps.com/Business/Account/Account-Management/Guest/Permissions

View only access

These guests can only view the customer account information pages, usage graphs, charges, bills, etc. They can make a payment, but can't perform any activity or subscription. This is the most common type of guest role.

- Make, edit and view scheduled payments (guests can only view/edit payments that they have made)
- Make one-time payments
- Make payments without login
- View AutoPay enrollment status
- View saved bank account
- View account balance

Limited access

These guests, in addition to the activities of the view only access role, are able to perform start/stop orders and change service plans, if applicable. This access is less common and is primarily meant for property managers who are responsible for multiple properties.

- Make, edit and view scheduled payments
- Make one-time payments
- Make payments without login
- View AutoPay enrollment status
- View saved bank account
- View account balance

In addition to view only access:

- Make service orders (start, stop or move service)

Full access

These guests, in addition to the activities of the view only access role, are able to perform start/stop orders and change service plans, if applicable. This access is also less common and is primarily meant for property managers who are responsible for multiple properties.

- Make service orders (start, stop and move service)

Response to SC 5.4 (continued):

- Make, edit and view scheduled payments
- Make one-time payments
- Make payments without login
- View AutoPay enrollment status
- View saved bank account
- View account balance

In addition to limited access:

- Enroll and manage AutoPay
- Make a payment arrangement

c.

i – vii: No.

d. Yes, but guest access must be manually revoked.

e. To manually revoke guest access, a customer would follow these steps:

1. Log in to the APS account and click the 'Manage accounts' icon. Alternatively, the customer can hover over 'Accounts and services' in the navigation and select 'View all accounts'.

2. To the right of each listed account number, there is a 'Guests' column which allows the customer to view how many guest users are on that particular account. Click on the three dots icon (ellipsis) icon and select 'Show details'.

3. Select the 'Guest users' tab to view the list of guests on the account. To the right of each guest's email address, the access type and status will be listed.

4. Select the 'Revoke guest' link located on the far right.

5. A message will appear to verify the request. Click the 'Remove' button and a confirmation message will appear indicating the action requested is complete. Guest user preferences will be removed when access is removed.

f. APS does not use the DataGuard Energy Data Privacy Program Voluntary Code of Conduct Final Concepts and Principles. APS does, however, use NIST CSF and GAPP Generally Accepted Privacy Principles for data security and privacy. Both frameworks cover the intent of DataGuard Energy Data Privacy Program Voluntary Code of Conduct Final Concepts and Principles.

Attachment CR-4

Multi-Year Rate Plans: Core Elements and Case Studies

Multi-Year Rate Plans

Core Elements and Case Studies

Prepared for Maryland PC51 and Case 9618

September 30, 2019

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1. CORE ELEMENTS OF MULTI-YEAR RATE PLANS

Multi-year rate plans (MRPs) are widely used around the world and have been in place for many decades in a variety of industries. MRPs are also known as "price cap regulation" or "revenue cap regulation." These approaches have also been referred to as "hands-off regulation" because the utility's costs are not closely examined during the duration of the plan. Instead, the utility's revenues are de-linked from its actual costs in combination with a rate case moratorium (typically lasting from three to five years).

Jurisdictions typically implement MRPs to achieve some or all of the following goals:

- Provide the utility with cost containment incentives
- Encourage innovation by allowing the utility to manage business decisions with greater flexibility.
- Reduce regulatory costs and burdens.
- Provide utilities with greater regulatory guidance and assurance regarding investments in new and innovative technologies to better align utility investments with energy policy goals.

Modern MRPs generally cap allowed revenues, rather than prices, in order to reduce the utility's throughput incentive and encourage the utility to focus on cost reductions rather than increasing revenues. The utility is typically allowed to retain some or all of the savings that it achieves through cost reductions during the duration of the rate plan.[1]

Under an MRP's rate case moratorium, the utility must refrain from filing a new rate case for the duration of the plan. This moratorium generally lasts three to eight years and ensures that the utility cannot simply come in for a new rate case if costs and revenues diverge. This shifts the risk associated with poor utility cost management to utility shareholders, rather than ratepayers, which strengthens the utility's cost containment incentives.

During the rate plan, revenues may either be held at a fixed level or be adjusted according to a pre-defined formula called an "attrition relief mechanism" or "ARM." An ARM may be based on an external cost index (such as inflation), cost forecasts, or a combination of the two. Importantly, the formula does not track the utility's *specific* costs. As explained in the Edison Electric Institute's survey of alternative

[1] However, as discussed in sections 3.1 and 4.2, when the utility's allowed revenues for capital investments are based on capital cost forecasts rather than external indexes, jurisdictions often require the utility to return any under-spend to ratepayers.

regulation mechanisms, "[t]he rate adjustments provided by ARMs are largely "external" in the sense that they give a utility an *allowance* for cost growth rather than reimbursement for its *actual* growth."[2]

In this manner, an MRP is similar to traditional cost of service regulation with a revenue decoupling mechanism, since the utility's costs do not necessarily equal revenues between rate cases, but the utility is still allowed to recover its allowed revenues (regardless of changes in sales). The primary differences from cost of service regulation with decoupling are:

- Allowed revenues can be increased annually through an ARM instead of frozen, and
- The utility agrees to not file another rate case for a set number of years (i.e., a rate case moratorium).

Because revenues do not increase in lock step with costs, the utility has an incentive to reduce costs to increase its profits for the duration of the rate plan. At the end of the MRP term, these cost reductions can then be passed on to ratepayers when rates are reset in a rate case.

To summarize, there are four key design elements that are critical to MRPs:

1) **Revenue Cap:** Revenues are capped at certain pre-determined levels.
2) **Attrition Relief Mechanism (ARM):** The initial year revenues may be escalated based on an index or cost forecast determined at the outset of the rate plan. Cost trackers may be added to the ARM for certain costs, particularly "exogenous" costs that the utility has no control over.
3) **Rate Case Moratorium:** A "stay-out" provision limits the ability for rates to be reset during the plan.
4) **Incentive to Improve Efficiency:** Utilities are incentivized to reduce costs during the plan by retaining some or all of the savings from efficiency gains.[3]

While MRPs can provide strong cost containment incentives and reduce regulatory burden, they also present two key risks. First, the utility's costs may deviate substantially from its allowed revenues during the rate plan. Second, the revenue adjustments provided by an index may not provide adequate revenue for new and unusual investments.

To address the first concern, regulators have often implemented consumer protection measures, such as earnings sharing mechanisms, to ensure that the utility does not over-earn excessively. For example, the utility may be allowed to earn 200 basis points above its allowed ROE, but beyond that it must share some of the extra earnings with customers.

[2] Mark N. Lowry, Matthew Makos, and Gretchen Waschbusch, "Alternative Regulation for Emerging Utility Challenges: 2015 Update" (Edison Electric Institute, November 11, 2015), 34.

[3] Conversely, ratepayers are protected from poor utility performance during the rate plan by being insulated from some or all of any increase in costs above the revenue cap.

To address the second concern, certain costs may be pulled out of the MRP and treated separately. For example, Massachusetts removed Eversource Energy's grid modernization investments from the MRP and is allowing recovery of those costs through a separate "Grid Modernization Factor."

Multi-Year Rate Plan Example: Massachusetts

Overview: Eversource Energy operates under an MRP that uses a revenue-indexing mechanism to adjust base rates, plus reconciliation of certain exogenous costs. The MRP has a five-year stay out period.

Revenue Index: Eversource's MRP allows for an adjustment of Base Rates using the rate of input price inflation representative of the electric distribution industry, less offsets for productivity and a consumer dividend.

Annual Adjustments: Effective January 1 of each year, the utility's Base Revenue Requirement is adjusted through an adjustment formula equal to the percentage change in the US Gross Domestic Product Price Inflation (GDPPI), plus a productivity adjustment of 1.56% minus a consumer dividend of 0.25%, plus an adjustment for exogenous costs.

Reconciliation of Exogenous Costs: Exogenous costs must (1) be beyond the utility's control; (2) arise from a change in accounting requirements or regulatory, judicial, or legislative directives; (3) be unique to the electric industry as opposed to the general economy; and (4) meet a threshold of "significance" of $5 million. The utility must present supporting documentation and rationale to the commission for consideration. Once allowed by the commission, the cost is recovered or returned in a separate factor to be reviewed and approved by the commission.

Recovery of Pre-authorized Grid Modernization Costs: All grid modernization-related capital and O&M expenditures are recovered separately and are subject to a targeted cost recovery cap. Specifically, the level of expenditures eligible for cost recovery through the Grid Modernization Factor shall not exceed the preauthorized three-year budgets.

Customer Protections: Earnings Sharing provides an important protection for customers in the event that expenses increase at a rate much lower than the revenue increases generated by the MRP revenue index. If the utility's actual ROE exceeds the utility's allowed ROE by 200 basis points, 75% of any additional earnings must be shared with customers.

***See:** NSTAR Electric Co. d/b/a Eversource Energy, Tariff Sheets M.D.P.U. No. 59A, filed February 16, 2018.*

2. Contrast to Formula Rate Plans

2.1. What is a Formula Rate Plan?

Both MRPs and formula rate plans (FRPs) feature formulas, thereby creating some confusion regarding the differences between the two approaches. The primary distinction is that formula rate plans formulaically ensure that revenues track costs, often measured as deviations in ROE from the utility's target ROE. If a utility's earned return is above its ROE target, it will be required to reduce its rates. Likewise, if a utility's earned return is below its target return it will be allowed to increase its rates. In contrast, MRPs do not adjust revenues to equal costs during the plan.[4]

A report by Edison Electric Institute describes a formula rate plan as "essentially a wide-scope cost tracker designed to help a utility's revenue track its cost of service."[5] The report explains how this works as follows:

> Earnings surpluses or deficits occur when revenue and cost are not balanced. FRPs have earnings true up mechanisms that adjust rates so that earnings variances are reduced or eliminated…. The earnings true up mechanism plays a key role in an FRP. Some mechanisms compare the earned ROE to the target ROE and then calculate the rate adjustment needed to reduce the ROE variance. Others adjust rates for the difference between revenue and a pro forma cost of service calculated using a rate of return target.[6]

In other words, formula rate plans true up revenues to costs once the ROE deviates from the allowed ROE by a certain amount. These true-ups are generally accompanied by some form of commission review and approval, but these reviews are more streamlined than those that occur in a general rate case.

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[4] With the possible exception of a limited set of cost trackers or reconciliations for specific types of costs.

[5] Mark N. Lowry, Matthew Makos, and Gretchen Waschbusch, "Alternative Regulation for Emerging Utility Challenges: 2015 Update" (Edison Electric Institute, November 11, 2015), 47.

[6] *Ibid.*

Alabama Power's Formula Rate Plan

Overview: Alabama Power Company operates under an FRP called the "Rate Stabilization and Equalization plan." Each year, the Alabama Public Service Commission compares the utility's projected ROE for the next year to its authorized ROE. If necessary, the utility's base rates are adjusted to keep the expected ROE within the authorized range, following a review of the reasonableness of the utility's costs.

Reconciliation Process: By December 1 of each year, the utility provides the commission with its projected ROE for the next year, together with an analysis of the main causes of any deviations from its authorized ROE and the need for any rate adjustment. During December, parties review and discuss the need for the rate adjustment, with any adjustments going into effect in January.

Customer Protections: Several customer protection measures are in place. Annual rate adjustments are capped at 5% to reduce rate shock. Once the utility's revenues are adjusted to match its projected costs for the upcoming year, the onus is on the utility to keep costs in check. If the utility fails to achieve its allowed ROE, no further reconciliation is made. However, if the utility's ROE exceeds its allowed ROE, then the excess is refunded to customers.

See: Laurence Kirsch and Mathew Morey, "Alternative Electricity Ratemaking Mechanisms Adopted by Other States" (Christensen Associates Energy Consulting, May 25, 2016), p. 11.

Entergy Arkansas, Inc.'s Formula Rate Plan

Overview: As required by 2015 Ark. Acts 2015 725, §3, formula rate plans in Arkansas use a formula based on the difference between a utility's target and earned return. If the utility's earned return exceeds its target return by 50 basis points, it is required to reduce its rates. Likewise, if the utility's earned return falls below its target return by 50 basis points, it is allowed to increase its rates.

Cost Forecasts: The utility may choose to use a projected test year or a historical test year. If a projected test year is used, the utility must file its cost forecasts in July of each year for the next calendar year period.

Reconciliation Process: If a projected test year is used, rate changes must include an adjustment to net any differences between the prior formula rate review test period change in revenue and the actual historical year change in revenue for that same year.

Regulatory Review: The review of cost forecasts, reconciliation, and approval of new rates occurs in a 180-day process that includes a public hearing.

Customer Protections: Annual rate adjustments for each rate class are capped at 4%.

See: AR Code § 23-4-1207 (2015)

2.2. Concerns with Formula Rate Plans

Commissions have generally been reluctant to adopt formula rate plans due to the problematic incentives they provide and recognition that these plans shift risk onto ratepayers. For example, the Maryland Public Service Commission noted that problems with formula rate plans include "tendency to shift financial risks toward customers, a concern that automatic adjustments may curtail the thorough review of utility costs, and reduced incentives for utilities to control costs."[7]

These concerns have been borne out by experience in jurisdictions where FRPs have been implemented. For example, in 2015, Act 725 was passed in Arkansas requiring that the Commission approve formula rate plans, but capped revenue increases under an FRP to 4% per year. Following passage of the Act, Entergy Arkansas, Inc. filed for a formula rate plan. In each subsequent year, Entergy has requested rate increases exceeding 4%, leading to concerns that the formula rate plan has not provided appropriate cost containment incentives. As explained by the Commission Staff,

> An FRP is an annual rider. It fundamentally accomplishes a higher level of certainty of recovery thus reducing risk to the utility.... The ability to increase revenues 4% each year is a considerable risk reduction for the utility.[8]

More specifically the Staff noted that an FRP:

- Reduces the time afforded for review of utility costs, which can serve to incentivize spending;
- Allows projections on projections, which incentivizes spending as compared to a regulatory framework where projections are based on what is otherwise historical information from which to make known and measurable changes;
- Incentivizes spending due to the annual rate adjustments. Once the FRP framework is selected by a utility, an outcome of a 4% increase each year (over the prior year) is less subject to challenge as long as the costs are prudently incurred and calculated in accordance with the tariff. The traditional regulatory tools in the Commission's toolkit are more limited under the FRP framework as the Commission has recognized;
- The unstated implication of the FRP statute is that the risk of an earnings review is effectively eliminated. There is no clear incentive to contain costs between annual FRP 4% increases. While the FRP framework states the rate change may be an increase or a decrease, the likelihood of a decrease is highly unlikely.[9]

[7] Maryland Public Service Commission, Order 89226, PC51, August 9, 2019, at 53.

[8] AR PSC Staff, Initial Brief Pursuant to Order No. 18, Docket 16-036-FR, January 1, 2019, at 17.

[9] *Id.*, at 18-19.

In its order, the Arkansas Commission agreed with Staff, stating that "many of the FRP processes, including a reduction in the time afforded for review, the use of projections, and annual rate adjustments do little to incentivize a utility to control its costs as compared to traditional ratemaking."[10]

In contrast, multi-year rate plans provide strong efficiency incentives precisely by *avoiding* cost true-ups. As noted in a Brattle report filed by the Joint Utilities in Maryland, "Multi-year rate plans typically have reconciliations **more limited in scope** and typically focused on capital expenditures, **to the extent that reconciliations are included at all** [emphasis added]."[11]

FORMULA RATES AND MINNESOTA'S MRP

When Minnesota was developing its rules for multiyear rate plans, various parties proposed different approaches to revenue adjustments during the rate plan.

- The Minnesota utilities favored favor formula rates, arguing that these rates could be more useful because they would adjust to reflect the latest data.
- Other parties opposed the use of automatic formulas for the purpose of adjusting rates to reflect new costs. They argued that formula rates would reduce a utility's incentive to operate efficiently and would be burdensome to supervise. Instead, these parties favored fixed multiyear rates. The rate case would establish the rates to be charged in each year of the multiyear rate plan; the rates for the first year might differ from the rates for later years, but the base rates for all years would be known by the end of the rate case.

Ultimately the Minnesota Public Utilities Commission declined to approve multiyear rate plans that rely on formula rates, noting that such rates reduce a utility's incentive to manage its costs. Moreover, the Commission observed that formula rates are unnecessary to achieve the purpose of a multiyear rate plan, stating that "Fixed multiyear rates permit prices to adjust over time to reflect anticipated changes in a utility's circumstances, yet can be established in a fact-driven ratemaking process built on a substantial evidentiary record." Consequently, the Commission directed utilities to propose fixed rates for each year of their plan when filing a multiyear rate plan.

See: Minnesota Public Utilities Commission, Docket No. E,G-999/M-12-587, Order Establishing Terms, Conditions, and Procedures for Multiyear Rate Plans, June 17, 2013, at 6-7.

10 Arkansas Public Service Commission, Order No. 21, Docket 16-036-FR, July 5, 2019.

11 The Brattle Group, Exploring the Use of Alternative Regulatory Mechanisms to Establish New Base Rates, Joint Utilities' Joint Initial Comments, Maryland PC51, March 2019.

3. Escalating Revenues During the MRP

Attrition relief mechanisms escalate a utility's allowed revenues over the course of an MRP. The ARM can be based on either an external price index or a cost forecast. With cost forecasts, information asymmetry is a serious concern, which has led many jurisdictions to opt for an index-based approach. We discuss both approaches below.

3.1. Revenues Escalated Based on Cost Forecasts

An ARM based on forecasts increases revenue by predetermined percentages in each plan year based, at least in part, on a utility's cost projections. The percentages can be different in each year, or the total increase can be levelized across the years.

To determine the revenue requirement for each year, both older capital investments (i.e., depreciation expense) and new capital additions must be accounted for. Depreciation expense is straight-forward to calculate, as older capital simply continues to depreciate. As noted in a recent report published by Lawrence Berkeley National Laboratories, the controversial issue lies in estimating the value of plant additions during the plan. The report explains that shortcuts are sometimes taken when estimating plant additions. For example:

- Plant additions may be set for each plan year at the utility's average value in recent years
- Plant additions may be set for each plan year at the value calculated in the test year of the most recent rate case
- Operation and maintenance expenses can be forecasted using index-based formulas.[12]

ARMs based on cost forecasts enable the utility's revenues to accommodate unusual investment trajectories, such as a capital investment surge. Since the ARM generally operates as a cap on revenues, it provides an incentive for the utility to ensure that actual investment costs are kept under the cost cap. However, forecasted ARMs are notoriously challenging for regulators, as it is difficult to ensure that the forecasts are reasonable due to asymmetry of information.

The National Regulatory Research Institute describes this issue as follows:

> Information asymmetry reflects the relatively less knowledge that a regulator has (relative to the utility's) on the correlation between forecasted costs and utility-management competence. When a utility files a cost forecast, how does the regulator know whether it reflects competent management? The analyst or auditor can evaluate the

[12] Mark Lowry et al., "State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities" (Lawrence Berkeley National Laboratory, July 2017), at 4.2, https://escholarship.org/uc/item/4r13j347.

> forecast applying state-of-the-art techniques; still, however, a level of uncertainty remains that leaves unknown the utility's level of managerial competence embedded in the forecast.[13]

Sophisticated approaches to reducing forecast bias are available, such as the menu approach used in the United Kingdom. Under this approach, the utility can choose among various combinations of allowed revenues and earnings sharing mechanisms, such as a plan with high revenues but for which it retains only a small portion of any cost savings, or a plan with low revenues but under which it can retain a higher portion of cost savings.

Regulators may also conduct independent benchmarking and engineering studies to determine the reasonableness of cost forecasts, but such endeavors are costly. In addition, regulators can check the accuracy of past cost forecasts and create performance incentive mechanisms for forecasting accuracy. Where cost forecasts are used to set allowed revenues, they are often accompanied by a one-way (downward) reconciliation mechanism, as is done in Minnesota and New York.

MRP Based on Cost Forecasts with One-Way Reconciliations

In 2017, the Minnesota Public Utilities Commission approved a settlement regarding Xcel Energy's multiyear rate plan application. The utility's initial application requested revenue increases supported by substantial documentation of the utility's proposed cost of service. During settlement proceedings, the annual revenue requirements were adjusted downward substantially, and generally became divorced from actual project costs.

The Minnesota Commission ultimately found the settlement reasonable, despite it no longer being tied to specific project costs, as the yearly rate increases were less inflation and significantly less than what Xcel initially proposed. Further, the settlement prohibited Xcel from filing another rate case until for four years or from seeking to institute any new riders for four years.

As an additional consumer protection measure, the settlement adopted a one-way capital-spending true-up, meaning that Xcel will make refunds if it spends less than it budgeted but cannot increase rates if it spends more. The true-up is based on aggregate capital spending, rather than individual projects. The Commission found that a true-up based on the aggregate amount of capital spending was reasonable given that Xcel's budget included approximately 1,800 capital projects. Nonetheless, the Commission also required that Xcel work with the Commission and Department of Commerce Staff to develop an annual capital-projects true-up compliance report that provides more granular data regarding project spending.

See: *Minnesota Public Utilities Commission, Findings of Fact, Conclusions, and Order, Docket E-002/GR-15-826, June 12, 2017.*

[13] Costello, "Multiyear Rate Plans and the Public Interest," 35–36.

3.2. Revenues Escalated Based on External Indexes

External indexes have historically been the preferred means by which to set a utility's allowed revenue requirements for future years of an MRP. In some cases, different categories of costs are escalated at different rates based on separate cost indexes. For example, IHS Global Insights provides cost escalation forecasts that are specific to the utility industry and are broken out by category of cost.

Indexes may be coupled with a "productivity factor." This productivity factor is often denoted as "X" and generally reflects the multifactor productivity of a group of peer utilities. In addition, a stretch factor (or "consumer dividend") may be added to the productivity factor in order to provide customers with a share of the benefit of the stronger performance incentives that are expected under the plan.[14] Further, "Y" and "Z" factors for unusual costs or costs outside of the utility's control may be added, as discussed in Section 4.1 below. The resulting escalation formula may look something like this:

$$\textit{Revenue Requirement}_{\textit{Year 2}} = \textit{Revenue Requirement}_{\textit{Year 1}} * (1 + \textit{Inflation} - X) + Y + Z$$

The California Public Utilities Commission has repeatedly rejected ARMs based on the utility's specific cost forecasts, opting instead to use inflation forecasts for different types of costs. In 2019, the California Commission adopted a capital escalation rate equal to the unweighted average of capital escalation rates across seven categories of costs, as shown in the table below:[15]

Unweighted Average of Capital Escalation Rates

	Year	
	2019	2020
Total Steam Production Plant	2.51%	2.54%
Total Hydraulic Production Plant	2.45%	2.40%
Total Other Production Plant	2.11%	2.64%
Total Transmission Plant	2.63%	2.62%
Total Distribution Plant	3.14%	3.18%
General Plant	1.82%	1.81%
Total Nuclear Palo Verde	2.55%	2.46%
Unweighted Average Across 2019-2020		**2.49%**

Escalating allowed revenues based on an external index permits the utility to continue making necessary investments and avoid revenue attrition, while avoiding concerns regarding strategic behavior (i.e., gaming of forecasts) and information asymmetry that are present in forecast-based ARMs.

3.3. Conclusions Regarding Revenue Escalation Approaches

To summarize, index-based revenue adjustment mechanisms have many advantages over cost forecasts:

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[14] Mark Lowry et al., "State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities" (Lawrence Berkeley National Laboratory, July 2017), 4.2, https://escholarship.org/uc/item/4r13j347.

[15] California Public Utilities Commission, D.19-05-020, Decision on Test Year 2018 General Rate Case for Southern California Edison Company, May 24, 2019, at 284.

- External cost indexes do not require that specific costs be reviewed and pre-approved at the beginning of the MRP. In contrast, basing revenue adjustments on a cost forecast essentially asks that the regulator pre-approve investments and their associated costs. This unduly shifts risks from the utility to the regulator and ultimately to ratepayers. Further, it increases the administrative burden for regulators and stakeholders.
- External cost indexes do not rely on utility cost forecasts that may be subject to error or may be over-inflated.

An index-based mechanism avoids the above challenges, but still allows utility revenues to increase over the term of the MRP, allowing for longer time between rate cases, without unduly shifting risk to ratepayers.

4. RECONCILIATION OF COSTS IN MRPS

Full reconciliations of costs and revenues in an MRP would be antithetical to the definition of an MRP. If revenues are trued up to equal the utility's actual costs, it erodes the utility's efficiency incentive, since the utility no longer benefits from implementing cost efficiencies and endures little risk if its costs exceed expectations. Broad annual true-ups would also essentially create annual rate cases, increasing the regulatory burden exponentially and erasing the benefits of the stay-out period.

However, some jurisdictions incorporate limited cost true-ups in MRPs. These true-ups often take the form of cost trackers for categories of costs that meet specific criteria and are limited in scope, such as costs that are outside the utility's control, or for a specific unusual capital investment.

When considering whether to implement any type of cost reconciliation mechanism, it is important to consider the impact on a utility's efficiency incentive and the impact on regulatory burden.

- If revenues are reconciled to actual costs, then the utility has reduced incentive to contain those costs.
- Under a broad reconciliation mechanism, the review required to determine that costs are reasonable imposes additional regulatory burden.

As emphasized by NRRI, "Regulators should avoid resetting annual rates based on a utility's actual cost in the absence of a prudence review…."[16] This means that any annual true-up based on actual costs would require a thorough examination of the utility's costs for prudence, which increases the regulatory burden. For these reasons, trackers and reconciliations should be used sparingly.

[16] Ken Costello, "Multiyear Rate Plans and the Public Interest," National Regulatory Research Institute, at 23.

4.1. Types of Costs that Are Often Reconciled in MRPs

In MRPs, cost reconciliations generally take some or all of the following forms:

A. Reconciliations for certain unusual, large investments
B. Reconciliations for recurring pass-through or mandated costs
C. Reconciliations or deferrals of one-time extraordinary costs

A. Reconciliations for Unusual, Large Costs ("K-Factor" Costs)

Large, unusual investments can be difficult to predict and incorporate into an MRP. Further, some investments may have impediments associated with their implementation, such as excessive risk or high capital costs. For example, the Massachusetts Department of Public Utilities found that utilities "may hesitate before making investments beyond what they deem necessary to ensure safe and reliable service, and that this reluctance may even exist "when the investments are cost-beneficial for a company but involve high capital costs, combined with regulatory lag and the potential for disallowed costs."[17]

For these reasons, large, unusual investments are sometimes addressed outside of an MRP's standard revenue requirement through a capital cost tracker or other reconciliation mechanism, often generically referred to as a "K-factor." In Massachusetts, such a factor was established for certain "foundational" grid modernization investments, as discussed in the box below.

[17] Massachusetts Department of Public Utilities, Order D.P.U. 12-76-A, Investigation by the Department of Public Utilities on its own Motion into Modernization of the Electric Grid, December 23, 2013, at 25. Available at https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/9241637

Reconciliation of Grid Modernization Costs in Massachusetts

Utilities may hesitate before making investments with high capital costs, particularly when combined with regulatory lag and the potential for disallowances. To encourage grid modernization, the commission in Massachusetts approved a targeted cost recovery mechanism called the "Grid Modernization Factor" or "GMF" for investments that are preauthorized by the commission.

Pre-authorization of investments and budgets: All grid modernization-related capital and O&M expenditures are subject to a targeted cost recovery cap. Specifically, the level of expenditures eligible for cost recovery through the GMF shall not exceed the preauthorized three-year budgets.

Cost Recovery: Costs are only eligible for recovery after the expenses have been incurred and the investments have been placed in service. The utilities file annual GMF rate adjustment and reconciliation filings comprised of: (1) actual, eligible preauthorized expenditures from the prior grid modernization plan investment year; and (2) a reconciliation component in the second year and beyond. Interest on over- or under-recovery of the revenue requirement is calculated on the average monthly balance using the customer deposit rate.

Annual Reconciliation Filings: On an annual basis, the utilities must file testimony and supporting exhibits with full project documentation of all grid modernization capital projects placed into service during the plan investment year and documentation of O&M expenses. The utilities must demonstrate that the costs sought for recovery are preauthorized, incremental, prudently incurred, in service, and used and useful (where applicable). Additionally, the filing shall also describe any cost variances as defined in the Companies' capital authorization policies, provide a demonstration that the proposed factors are calculated appropriately, and provide bill impact estimates.

See: *Massachusetts Department of Public Utilities, Order D.P.U. 15-122, May 10, 2018, at 216-235. Available at https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/9163507*

B. Reconciliations for Recurring Pass-Through or Mandated Costs ("Y-Factor" Costs)

Recurring costs that are volatile and outside of utility control may be fully or partially reconciled during an MRP using cost trackers or deferral mechanisms. In Alberta, these costs are referred to as "Y-Factor" costs. The Alberta Commission established the following criterial for costs eligible for Y-Factor treatment:

1) The costs must be attributable to events outside management's control.
2) The costs must be material. They must have a significant influence on the operation of the company otherwise the costs should be expensed or recognized as income, in the normal course of business.
3) The costs should not have a significant influence on the inflation factor in the [MRP revenue] formulas.
4) The costs must be prudently incurred.

5) All costs must be of a recurring nature, and there must be the potential for a high level of variability in the annual financial impacts.[18]

New York allows reconciliations only for costs that "are difficult to forecast with certainty and are largely beyond the direct control of utility management."[19] In New York, reconciliation and/or deferral accounting mechanisms have been used for costs including:

- Taxes
- Pensions/other post-employment benefits (OPEBs)
- Environmental remediation costs
- Regional Greenhouse Gas Initiative ("RGGI") costs
- System Benefits Charges
- Energy Efficiency Portfolio Standard charges and Demand Side Management costs
- New York Public Service Law §18-a regulatory assessment (for commission costs)
- Market supply charges
- Cost of the Low Income customer charge discounts[20]

We note, however, that some of these reconciliations have been only partial in order to preserve some incentive for the utility to manage the costs efficiently. In Consolidated Edison's MRP, if property taxes varied in any Rate Year from the projected level provided in rates, only 80% of the variation would be deferred and either recovered from or credited to customers, subject to a cap on the Company's share equal to 10 basis points on common equity for each Rate Year.[21]

In its order approving ConEdison's MRP, the New York Public Service Commission explained that asymmetrical and partial reconciliations for certain costs "provide the Company an incentive to manage such costs to the extent practicable." The Commission further noted that such reconciliation provisions decrease the volatility of a company's earnings and transfer risk to ratepayers, which allows the Commission to reduce the allowed return on equity in rate proceedings. The Commission explains that this "is one of the prime reasons returns allowed in New York are and can be lower than those in many other jurisdictions."[22] It is reasonable that any reconciliations and reduced risk to the utility be accompanied by a commensurate reduction in the utility's allowed ROE.

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[18] Alberta Utilities Commission, Decision 2012-237, September 12, 2012, at 135.

[19] Order Approving Electric, Gas and Steam Rate Plans in Accord with Joint Proposal, Case 13-E-0030, Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service, February 21, 2014, at 26. Available at http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={1714A09D-088F-4343-BF91-8DEA3685A614}

[20] Order Approving Electric, Gas and Steam Rate Plans in Accord with Joint Proposal, Case 13-E-0030, Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service, February 21, 2014.

[21] Joint Proposal, CASE 09-E-0428- Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service, November 24, 2009, at 18.

[22] Order Approving Electric, Gas and Steam Rate Plans in Accord with Joint Proposal, Case 13-E-0030, Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service, February 21, 2014, at 29-30.

C. Reconciliations of One-Time Extraordinary Costs ("Z-Factor Costs")

In an MRP, true-ups can be appropriate for exceptional costs that have a material effect on the utility's costs, are beyond the control of utility management, and which were incurred reasonably (such as extraordinary storm response costs). For example,

- New York's MRPs allowed cumulative major storm damage expenses in excess of a certain threshold to be deferred. The expenses would be subject to New York Department of Public Service Staff review.[23]

- California has utilized "Z-factors" to reconcile items that meet the following criteria:
  1. The event must be exogenous to the utility;
  2. The event must occur after implementation of rates;
  3. The costs are beyond the control of the utility management;
  4. The costs are a normal part of doing business;
  5. The costs must have a disproportionate impact on the utility;
  6. The costs and event are not reflected in the rate update mechanism;
  7. The costs must have a major impact on overall costs;
  8. The cost impact must be measurable; and
  9. The utility must incur the cost reasonably.[24]

4.2. One-Way Reconciliations of Costs

As discussed above, the most common means of adjusting allowed revenues during the rate plan is the index approach. However, some jurisdictions use cost forecasts, or a combination of external indexes and cost forecasts. Where cost forecasts are used, they are frequently accompanied by one-way (downward) reconciliations of costs.

A key challenge associated with the use of cost forecasts is that the utility has an incentive to inflate cost projections. As the Alberta Public Utilities Commission noted, unless there is a reconciliation mechanism, basing revenues on cost forecasts "creates the opportunity for the distribution utility to benefit from exaggerating its forecasts and puts more pressure on the Commission to ensure the forecasts are reasonable." Further, the Alberta Commission notes its "concerns about over-forecasting and asymmetrical information and finds that an incremental capital mechanism that includes a forecasting component but lacks a true-up is problematic because it incorporates the unacceptable forecasting incentives…"[25]

A one-way reconciliation mechanism reduces the benefit that the utility receives from inflating its cost projections and protects customers from utility under-spend. The one-way nature of the reconciliation

[23] Joint Proposal, CASE 09-E-0428- Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service, November 24, 2009, at 24.

[24] California Public Utilities Commission, D1408032, Authorizing PG&E's GRC Revenue Requirement for 2014-2016, at 661.

[25] Alberta Utilities Commission, Decision 20414-D01-2016, December 16, 2016, at 53.

also encourages the utility to keep costs below the projections and ensures that over-spends are not approved until a prudency review in the subsequent rate case. However, the one-way nature of the reconciliation still incentivizes the utility to inflate its capital projections to ensure that it does not exceed its capital cost forecast. Just as importantly, it provides no incentive to increase efficiency.[26]

Minnesota and New York both use cost forecasts to project revenue requirements associated with capital investments, but have coupled the forecasts with a one-way (downward) reconciliation mechanism. New York's approach is discussed in the box below.

NEW YORK'S "CLAW-BACK MECHANISM"

A one-way reconciliation mechanism is used in New York and referred to as the "Net Plant Reconciliation Mechanism" or "claw-back mechanism." The New York Public Service Commission describes this mechanism for Consolidated Edison as follows:

> If the Company's actual average net plant in service for each of the three categories of capital expenditures is less than that category's projected average plant-in-service balance..., the Company will defer the carrying costs associated with the difference for the benefit of ratepayers. If the Company exceeds the net plant-in-service targets, it must absorb the related carrying costs during the term of the rate plan. Con Edison must justify the need for, the reasonableness of, and its inability to reasonably avoid any such over-target expenditures in its next rate case filing. In addition, the revenue requirement associated with any such Commission-approved over-target expenditures from Rate Year 1, after the term of the rate plan and for the book life of the investment, will be calculated based on an assumption that the over-target expenditures were not financed by both common equity and debt, but rather solely by debt.

See: *New York Public Service Commission, Order Establishing Three-Year Electric Rate Plan, Case 09-E-0428, March 26, 2010, at 11.*

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[26] The California Public Utilities Commission (CPUC) has objected to such claw-back mechanisms precisely because it erodes the utility's incentive to be efficient. The CPUC explains:

> "...we are extending to utility management an opportunity and incentive to find ways to conduct operations for less than projected. When it can do this it flows the benefit to the utility's bottom line, which means profit. In the short term, between general rate proceedings, the shareholders benefit when the company's management can 'do it for less,' and correspondingly, ratepayers ultimately benefit because the productivity improvement will be reflected periodically when there is a comprehensive review of the utility's revenue requirement. Keeping this incentive for utility management is a cornerstone of ratemaking, which leads us to look askance at proposals for immediate 'give backs' of all cost savings to ratepayers. If ratemaking ever becomes so conceptually upside down that utility management loses the economic incentive to exercise its business acumen, California will be in a sad posture and will suffer under utility management which is lethargic with a 'cost plus' mentality."

See: California Public Utilities Commission, D.85-03-042, 17 CPUC2d 246, at 254, as cited in D.19-05-020, Decision on Test Year 2018 General Rate Case for Southern California Edison Company, May 24, 2019, at 152.

5. OTHER COMPONENTS OF MRPS

5.1. Earnings Sharing Mechanisms

Earnings sharing mechanisms are primarily implemented to ensure that utility earnings do not become excessive during multi-year rate plans. The vast majority of these earnings sharing mechanisms are one-way adjustments that cap the potential over-earning of the utility and require that the utility share some of its over-earnings with customers. As noted by the Brattle Group, earnings sharing mechanisms that apply to "utility over earnings (but not under earnings) are in place in 10 states."[27] Only one state (Hawaii) is considering an earnings sharing mechanism for under-earnings as well.

Four states with MRPs have no earnings sharing mechanisms at all, allowing the utility to retain all over-earnings or suffer any under-earnings. Where earnings sharing mechanisms are used, there is the risk that the utility's efficiency incentives will be blunted. Thus, to preserve utility incentives, many of the states with earnings sharing mechanisms also apply a deadband where a utility is not required to share excess earnings with customers.

In Massachusetts, the deadband for earnings sharing is 200 basis points for Eversource. If the utility's ROE exceeds its allowed ROE by 200 basis points, it must return 75% of additional earnings (beyond 200 basis point) to ratepayers. In Iowa, the commission set MidAmerican's allowed ROE at 10% and then required that earnings between 11% and 14% be shared 80% with ratepayers. Beyond an earned ROE of 14%, all of the excess earnings are to be returned to ratepayers.[28]

5.2. Rate Plan Duration

MRPs are usually last between three and five years, although the plans in the United Kingdom last for eight years. There are several distinct advantages to plans that are shorter in duration:

- Shorter plans require less up-front investment in time and resources (modeling, review).
- Shorter plans present less risk associated with getting the forecasts wrong.

However, shorter plans also provide much weaker incentives for a utility to reduce its costs, as any cost reductions will quickly pass on to ratepayers at the time of the next rate case (unless efficiency carryover mechanisms are used).[29]

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[27] Pepco Exhibit J, Witness Zarakas, in FC 1156, The Application of the Potomac Electric Power Company Authority to Implement a Multiyear Rate Plan for Electric Distribution Service in the District of Columbia, at 13.

[28] Iowa Utilities Board, Order Approving Settlement, with Modifications, and Requiring Additional Information, Docket No. RPU-2013-0004, March 17, 2014.

[29] Efficiency carryover mechanisms allow for the utility to retain a share of its savings from efficiency improvements for a set period of time when a multiyear rate plan expires. For more information, see Mark Lowry et al., "State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities" (Lawrence Berkeley National Laboratory, July 2017), at 4.8-4.10, https://escholarship.org/uc/item/4r13j347.

In contrast, longer plans provide greater innovation incentives (due to more time for utility to reap rewards from innovation and efficiencies). Longer plans also reduce the frequency of rate cases and therefore possibly reduce overall costs of regulation.

5.3. Reopener Provisions

Reopeners permit a reassessment of the utility's revenues and costs with the potential to make adjustments. A utility would be expected to request a reopener if it was under-earning, while a regulator or other stakeholder would be expected to request a reopener if they felt the utility was over-earning. However, use of reopeners can dilute incentives for the utility to operate efficiently, since the utility knows it can simply come back in and ask for more revenues, or the utility knows that if it operates too efficiently, its higher earnings will be taken away prematurely. Establishing clear criteria for reopening rate plans at the outset can help avoid reopening rate plans except when absolutely necessary.

In Minnesota, a utility that receives Commission approval of its multiyear rate plan must delay filing a new rate case until after the plan expires. However, utilities still retain the discretion to request rate relief from the Commission under Minn. Stat. § 216B.16, subd. 19 (c).

5.4. Performance Incentive Mechanisms

Under an MRP regulatory framework, utilities retain some or all of the savings achieved through cost reductions. This can create an incentive to cut costs at the expense of service quality. To combat this incentive, regulators have historically coupled MRPs with performance incentive mechanisms (PIMs) to prevent service quality degradation. Increasingly, PIMs are also increasingly being used to promote other outcomes, such as emissions reductions, as well as to ensure that a utility follows through on its commitments, such as investments in grid modernization.

Attachment CR-5

Utility Models: Questions for Regulators and Stakeholders to Ask and Answer as Utilities Evolve

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UTILITY MODELS:

QUESTIONS FOR REGULATORS AND STAKEHOLDERS TO ASK AND ANSWER AS UTILITIES EVOLVE

BY RON LEHR & SONIA AGGARWAL ● FEBRUARY 2017

Every utility regulatory model has embedded incentives. This list is intended to help state policymakers and other stakeholders pinpoint questions they can ask and answer to explore how incentives from cost of service regulation and performance regulation relate to today's power system goals.[*]

QUESTIONS FOR STATES WITH COST OF SERVICE REGULATION

- What types of utility activities or investments does the current financial structure incent? Is it equipped to provide comprehensive and coordinated solutions across issues facing utilities today and in the future?
- What do customers want? What role does customer satisfaction play in utility profitability?
- What policy, financial, market, and operational considerations, constraints, and opportunities should be analyzed to determine an appropriate role for utilities going forward? Should they be the sole providers of electricity services or should they enable a role for customers and third-party providers?
- Are current financial incentives for utilities aligned with efficient utility operations, adequate and reliable service for consumers, and just and reasonable rates? Are they aligned with goals for environmental performance?
- In addition to well-known monopoly incentives, have utility monopsony incentives been analyzed? Are there ways to regulate monopsony incentives in the public interest?

[*] For more information, see:
http://energyinnovation.org/resources/our-publications/going-deep-performance-based-regulation/
http://westernenergyboard.org/wp-content/uploads/2015/03/03-09-15-Synapse-WIEB-Utility-Performance-Incentives
http://americaspowerplan.org

- How will today's regulation lead utilities toward constructive responses to new challenges that require innovation, such as new technology, changing customer preferences, security, and storm damage recovery? Does today's regulation reward adaptation and innovation?
- How does current utility planning handle risk management? What does this mean for customers? For utility investors?
- What is the state of communications and trust among those engaged in regulation? Are communications open and broad-ranging or constrained to taking positions in formal, litigated cases? Are there opportunities to improve the amount and quality of utility stakeholder communications?
- If commission time and resources are constrained, is there potential to reorient away from case dispute resolution and toward longer-term policy and planning?
- Could formula-based approaches or revenue caps with periodic, planned rate cases provide a more efficient way to set rates?

QUESTIONS FOR STATES ASSESSING PROPOSALS FOR PERFORMANCE REGULATION

- What standards, metrics, or measurements are already in place and how has the utility performed against those? How do these complement newly proposed incentives?
- Have the overall goals of the performance regulation program been clearly defined?
- Have particular outputs and quantitative metrics been associated with overall program goals? Can these metrics be tracked and verified with existing or easily-obtained data?
- How do the new goals and metrics relate to existing standards and metrics?
- Who are the stakeholders—those with a stake in utility goals sufficient to motivate their inclusion in discussions about defining those goals? Have they been adequately consulted?
- How will future performance be reported? Would a template or a scorecard be appropriate?
- Is there sufficient knowledge about historical and likely future utility performance to set ambitious but reasonable targets for new metrics? How far into the future should targets be set in order to give utilities adequate time to pursue sustainable new business activities?
- Would incentives and penalties be appropriate to focus utility endeavors on new goals? Would it be appropriate to incent or penalize performance on some of the metrics and track others for future consideration?
- What is an appropriate overall financial impact on the utility for the full set of incentives and penalties? How does this relate to the level of ambition of the targets? Is a higher return appropriate for utilities if they take on more risk to facilitate the transition?

- Are the costs and benefits of performance incentives reasonably balanced? Are symmetrical or asymmetrical performance rewards and penalties better suited to the circumstances? What would capture utility management attention? How should effects on utility investors be factored into this calculus?
- What is the trade-off between tying metrics as closely to goals as possible and ensuring performance is firmly within the utility's control? Are there ways utilities can influence outcomes they may not directly control?
- Are there factors against which utility performance should be normalized, such as weather or regional economic development?
- Beyond normalization, are there other ways to build in opportunities for metrics, targets, or financial incentives to evolve in response to changing circumstances and measured performance, without introducing unnecessary risk into the program?

BEFORE THE
ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN.	Docket No. E-01345A-19-0236

Direct Testimony

of

Tyler Comings

REDACTED VERSION

On Behalf of
Sierra Club

October 2, 2020

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Attachment TC-1: Resume of Tyler Comings

Attachment TC-2: Public Discovery Responses

Attachment TC-3: Confidential Discovery Responses

Attachment TC-4: Highly Confidential Discovery Responses

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, business address, and position.

A. My name is Tyler Comings. I am a Senior Researcher at Applied Economics Clinic, located at 1012 Massachusetts Avenue, Arlington, Massachusetts.

Q. Please describe Applied Economics Clinic.

A. The Applied Economics Clinic is a 501(c)(3) non-profit consulting group housed at Tufts University's Global Development and Environment Institute. Founded in February 2017, the Clinic provides expert testimony, analysis, modeling, policy briefs, and reports for public interest groups, including many government entities, on the topics of energy, environment, consumer protection, and equity, while providing on-the-job training to a new generation of technical experts.

Q. Please summarize your work experience and educational background.

A. I have 14 years of experience in economic research and consulting. At Applied Economics Clinic, I focus on energy system planning, costs of regulatory compliance, wholesale electricity markets, utility finance, and economic impact analyses. I have provided testimony on these topics in Colorado, the District of Columbia, Hawaii, Indiana, Kentucky, Maryland, Michigan, Missouri, New Jersey, New Mexico, Ohio, Oklahoma, West Virginia, and Nova Scotia (Canada). I am also a Certified Rate of Return Analyst (CRRA) and member of the Society of Utility and Regulatory Financial Analysts (SURFA).

I have provided expertise for many public-interest clients including: American Association of Retired Persons (AARP), Appalachian Regional Commission, Citizens Action Coalition of Indiana, City of Atlanta, Consumers Union, District of Columbia Office of the People's Counsel, District of Columbia Government, Earthjustice, Energy Future Coalition, Hawaii Division of Consumer Advocacy, Illinois Attorney General, Maryland Office of the People's Counsel, Massachusetts Energy Efficiency Advisory Council, Massachusetts Division of Insurance, Michigan Agency for Energy, Montana Consumer Counsel, Mountain Association for Community Economic Development, Nevada State Office of Energy, New Jersey Division of Rate Counsel, New York State Energy Research and Development, Nova Scotia Utility and Review Board Counsel, Rhode Island Office of Energy Resources, Sierra Club, Southern Environmental Law Center, U.S. Department of Justice, Vermont Department of Public Service, West Virginia Consumer Advocate Division, and Wisconsin Department of Administration.

I was previously employed at Synapse Energy Economics, where I provided expert testimony and reports on coal plant economics and utility system planning. Prior to that, I performed research on consumer finance and behavioral economics at Ideas42 and conducted economic impact and benefit-cost analysis of energy and transportation investments at EDR Group.

I hold a B.A. in Mathematics and Economics from Boston University and an M.A. in Economics from Tufts University.

My full resume is attached as Attachment TC-1.

Q. On whose behalf are you testifying in this case?

A. I am testifying on behalf of Sierra Club.

Q. Have you testified before the Arizona Corporation Commission previously?

A. No.

Q. Have you testified before other public utility commissions in other jurisdictions?

A. Yes. I have testified before commissions in Colorado, the District of Columbia, Hawaii, Indiana, Kentucky, Maryland, Michigan, Missouri, New Jersey, New Mexico, Ohio, Oklahoma, West Virginia, and Nova Scotia (Canada).

Q. What is the purpose of your testimony?

A. The focus of my testimony is the request by Arizona Public Service Company (APS or the Company) for recovery of costs associated with two coal units, Four Corners Units 4 and 5. First, I discuss past decision-making on expenditures at these units and how the units' economics have changed over time. Second, I conduct a forward-looking economic assessment of both units. Finally, I recommend how these units' costs should be treated in this case and how future resource planning for units 4 and 5 should be conducted.

Q. Please summarize your findings and recommendations.

A. Based on my analysis of the Company's filing and data responses in this case, I conclude that:

1. **The Company has continually failed to justify the continued operation and investment in Four Corners Units 4 and 5.** Since the Company acquired its current share of ownership of these two units in 2013, the economics of continuing to operate them has markedly worsened. The cost of

[redacted] while the costs of competing resources have decreased. Renewable and storage resource costs have dropped dramatically and are widely expected to continue to decline. Gas prices have remained low, and industry-wide forecasts of future gas prices have decreased dramatically. Despite these trends, since APS acquired its current share in 2013, the Company has failed to evaluate retiring and replacing Four Corners Units 4 and 5 before 2031.

2. **I found that the units are too costly to justify continued operation; therefore, I recommend that they be retired as soon as possible.** I conducted a forward-looking economic assessment of these units—comparing a 2023 retirement to the Company's currently planned 2031 retirement. Relying on the Company's projected costs of the two units through 2031 (including in its 2020 IRP), I find that there would be substantial savings from early retirement across a wide range of assumptions. For instance, using the Company's 2020 IRP base case scenario, I estimate savings between [redacted] Importantly, these savings would occur even if the costs of past expenditures (such as the selective catalytic reduction or "SCR") were allowed into rates. I also accounted for differences in termination costs between the two retirement years—including those at the Navajo Mine. With these substantial savings, the Company should plan to retire the units as soon as possible, issue a competitive solicitation for a wide and robust sample of replacement options, and plan for a just and equitable transition for the affected communities.

3. **I recommend that the Commission disallow costs that are unnecessary for the units continued operation and require an early retirement analysis in the 2020 IRP.** The Company has failed to justify continued operation of these two units, and I find that there would be substantial customer savings with their earlier retirement. Further expenditures made with a 2031 retirement in-mind are imprudent. Only those costs that are necessary for safe, near-term operation should be allowed in rates at this time. Moreover, the Company's recently released 2020 IRP fails to evaluate retirement of the units prior to 2031. If APS does not decide to retire the units by end-of-year 2023, the Commission should require that the Company evaluate earlier retirement in the 2020 IRP and subsequent IRPs. I am aware that Chairman Burns has requested that APS model accelerated depreciation and securitization for a variety of retirement dates for the Four Corners power plant, including 2023.[1] I may provide responsive testimony evaluating APS's response once it is received.

II. THE COMPANY HAS REPEATEDLY FAILED TO JUSTIFY CONTINUED OPERATION AND INVESTMENT IN FOUR CORNERS UNITS 4 AND 5

Q. Please summarize this section.

A. In this section, I discuss the Company's past planning regarding Four Corners Units 4 and 5, focusing on modeling in the Company's Integrated Resource Plans ("IRPs"). The Company has repeatedly failed to seriously evaluate the units' future even as the

[1] Letter from Chairman Burns, Docket No. E-01345A-19-0236 (Sept. 1, 2020), *available at* https://docket.images.azcc.gov/E000008707.pdf.

[redacted] and other resource options became more cost competitive. The Company has had several opportunities to re-assess earlier retirement of these units, including prior to making a major investment in SCR pollution controls for the units.

Q. Please describe Four Corners Units 4 and 5.

A. Four Corners Units 4 and 5 are two 770 MW coal-fired units (1,540 MW total) located near Farmington, New Mexico, which began operation in 1969 and 1970, respectively.[2] APS currently owns 63 percent of these two units, totaling 970 MW of capacity for the Company.[3] The Company previously owned 15 percent of the units but purchased another 48 percent share from Southern California Edison ("SCE") in 2013. The remaining shares of the units are co-owned by Public Service of New Mexico (13 percent), Salt River Project (10 percent), Tucson Electric Power (7 percent), and Navajo Transitional Energy Company (7 percent).[4] The source of fuel for the units is the Navajo Mine owned by Navajo Transitional Energy Company (NTEC), located near the two units in northwestern New Mexico. NTEC has a contract to provide coal for the units through 2031.[5]

[2] Ariz. Pub. Serv., *2020 Integrated Resource Plan* at 52 (June 26, 2020), *available at* https://docket.images.azcc.gov/E000007312.pdf [hereinafter "2020 IRP"].
[3] *Id.*
[4] *See* Salt River Project, *Four Corners Power Plant,* https://www.srpnet.com/about/stations/fourcorners.aspx (last visited July 27, 2020).
[5] Ariz. Pub. Serv. Application at 163, Schedule E-9, Docket No. E-01345A-19-0236 (Nov. 11, 2019), *available at* https://docket.images.azcc.gov/E000003517.pdf.

Q. How long is the Company planning to continue operating these units?

A. The Company is currently planning to retire Four Corners Units 4 and 5 in 2031, coinciding with the end of the coal contract with NTEC. The Company had previously planned to operate the units until 2038, and the depreciation period in this case remains through 2038.[6] However, APS announced in January of this year that it was ceasing all coal operations at Four Corners in 2031.[7]

Q. Are plans for the units' future operations relevant to this current rate case?

A. Yes. The Company is requesting approval to charge customers for hundreds of millions of dollars in test-year and post-test year capital and operating costs associated with the two units in this case, while assuming that they will operate until 2031.[8] Whether these units should be operating through 2031 is germane to the prudence of continued expenditures at these units, and whether recovery of such spending (and associated rate of return) from ratepayers should be allowed. For instance, spending on all currently planned capital and maintenance may no longer be necessary or cost-effective. Put differently, some spending might be "avoidable" if units were retired earlier than 2031. Including this "avoidable" spending in rates

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[6] Direct Testimony of Elizabeth A. Blankenship at 30:4-5 [hereinafter "Blankenship Direct"].

[7] Press Release, Ariz. Pub. Serv., *APS sets course for 100 percent clean energy future* (Jan. 22, 2020), *available at* https://www.aps.com/en/About/Our-Company/Newsroom/Articles/APS-sets-course-for-100-percent-clean-energy-future.

[8] For Four Corners 4 and 5 specifically, Exhibit BDL-4DR includes $10.1 million in "total projected costs"; Exhibit BDL-5DR includes $58.9 million in "total projected costs." For the adjusted test year, the Company is including $187.5 million in fuel expense and $101.9 million in non-fuel operations and maintenance. *See* APS Response to SC DR 1.17. All public discovery responses referenced in this testimony are compiled and available within Attachment TC-2 ["Attach. TC-2"].

now would prevent ratepayers from realizing this savings should the units retire before 2031.

Q. Please describe the history of APS's investments in Four Corners Units 4 and 5.

A. Below is a timeline of events relevant to the Company's current ownership of the two units:

- <u>November 2010:</u> The Company applies for Commission approval to purchase SCE's 48 percent share in Four Corners Units 4 and 5.[9]
- <u>March 2012:</u> The Company releases its 2012 IRP which considers portfolios with and without the acquisition.[10]
- <u>April 2012:</u> The Commission rules that the Company should delay the SCE transaction in "order to minimize the rate impact to customers…".[11] However, the Commission does not rule on the prudence of the transaction.[12]
- <u>December 2013:</u> The Company finalizes its purchase of SCE's 48 percent share in the two units, increasing APS's ownership share to 63 percent.[13]

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[9] Ariz. Pub. Serv. Application, Docket No. E-01345A-10-0474, (Ariz. Corp. Comm'n Nov. 22, 2010), *available at* https://docket.images.azcc.gov/0000120291.pdf.
[10] Ariz. Pub. Serv., *2012 Integrated Resource Plan* at 44 (Dec. 11, 2012), *available at* https://docket.images.azcc.gov/0000135557.pdf [hereinafter "2012 IRP"].
[11] Decision No. 73130 at 43:8-9, Docket No. E-01345A-10-0474 (Ariz. Corp. Comm'n Apr. 24, 2012).
[12] *Id.* at 42.
[13] Ariz. Pub. Serv., *2014 Integrated Resource Plan* at 12 (Dec. 19, 2014), *available at* https://docket.images.azcc.gov/0000152210.pdf [hereinafter "2014 IRP"].

The co-owners of the units sign a coal contract with the Navajo mine for 2016 through 2031.[14]

- April 2014: The Company releases its 2014 IRP where all portfolios assume that the two units operate through 2038.[15]
- December 2014: The Commission rules that APS's acquisition of SCE's share is prudent and allows acquisition costs to be included in rates.[16]
- August-September 2015: The Company signs the contract for the installation of SCR pollution controls and commences construction at the two units.[17]
- April 2017: The Company releases its 2017 IRP, which considers one portfolio where the two units retire in 2031. In the other six portfolios—including APS's preferred portfolio—the units are retired in 2038.[18]
- April 2018: SCRs are operational at the two units for a final cost of $625 million.[19] The Company requests that its share of these SCR costs be included in rates.[20]
- November 2018: Administrative Law Judge (ALJ) recommends that the SCRs installation projects were completed in a "prudent manner" and that

[14] Katherine Locke, *Navajo Energy Company buys coal mine*, NAVAJO-HOPI OBSERVER, Jan. 7, 2014, *available at* https://www.nhonews.com/news/2014/jan/07/navajo-energy-company-buys-coal-mine/.
[15] 2014 IRP at 55, 231.
[16] Decision No. 74876 at 46:13-15, Docket No. E-01345A-11-0224 (Ariz. Corp. Comm'n Dec. 23, 2014).
[17] Attach. TC-2, APS Response to Sierra Club DR 1.27(e)(i).
[18] Ariz. Pub. Serv., *2017 Integrated Resource Plan* at 13, 259 (Apr. 2017), *available at* https://docket.images.azcc.gov/0000168766.pdf [hereinafter "2017 IRP"].
[19] Recommended Opinion and Order from the Hearing Division at 6:15-18, 22:6-7, Docket No. E-01345A-16-0036 (Ariz. Corp. Comm'n Nov. 27, 2018), *available at* https://docket.images.azcc.gov/0000193887.pdf [hereinafter "ALJ Recommendation"].
[20] Direct Testimony of Barbara D. Lockwood at 8:5-8.

APS's share of $383 million should be included in rate base.[21] (As of this writing, the Commission has yet to rule on the prudence of the SCRs.)

- January 2020: The Company decides to retire Four Corners Units 4 and 5 in 2031.[22]

Q. Are you recommending disallowances related to the Company's past decisions and investments in Four Corners Units 4 and 5?

A. No. My recommendations are related to future costs at the units, which I discuss in more detail below. But it is important to review the Company's past decision-making to provide context for future decisions surrounding these two coal units. While I do not provide a recommendation on disallowances for past investments—such as the SCR costs—that should not be taken as recommending that the Commission find those decisions prudent.

Q. Has the Company considered retiring the units prior to 2031 since it acquired its current share of ownership?

A. No. Since APS acquired its current 63 percent share in 2013, the one notable change in the Company's decision making was for these units to retire in 2031 rather than 2038. However, APS has not considered retirement before 2031 in any of its planning following the 2013 acquisition, as I discuss below.

[21] ALJ Recommendation at 10:3-5, 22:6-7.
[22] *See supra* note 7.

A. <u>Following the Acquisition of Four Corners Units 4 and 5, Gas Price Forecasts Increasingly Made Coal Generation Less Competitive</u>

Q. Did the Company consider not acquiring its current share in these units?

A. Yes. In the 2012 IRP, the Company had not yet finalized the purchase of the 48 percent share in Four Corners Units 4 and 5 from SCE. APS modeled four portfolios: two portfolios did not include the SCE acquisition ("Coal Retirement" and "Four Corners Contingency"); and two portfolios assumed the SCE acquisition was finalized ("Base Case" and "Enhanced Renewable").[23] The latter two portfolios—including the Company's preferred portfolio ("Base Case")—assumed the acquisition would be finalized and that Four Corners Units 4 and 5 would operate until 2038.[24] The Base Case was found to be the lowest-cost of these four portfolios under the Company's base gas price forecast.

Q. In the 2012 IRP, what were the Company's findings under a low gas price future?

A. APS's 2012 IRP found that not acquiring the two units would have provided substantial savings if gas prices remained low. Using APS's low gas price forecast, the "Four Corners Contingency" portfolio, where the Company did not acquire Four Corners Units 4 and 5, was found to save $497 million net present value (NPV) over a 30-year period (2012-2041) or save $230 million over a 16-year period (2012-2027), compared to the Base Case portfolio that included the acquisition.[25]

[23] 2012 IRP at 52.
[24] *Id.* at ATT-23.
[25] *Id.* at ATT-95. All portfolios assumed the retirement of Four Corners Units 1-3. *See id.* at 139-140.

Thus, there was substantial savings from not acquiring the units in a low gas price future. Moreover, the APS low gas price forecast would be considered far too high by the industry today: The 2012 IRP low gas price forecast for 2019 was $4.68 per MMBtu—almost double the actual 2019 Henry Hub price of $2.56 per MMBtu.[26]

Q. How do low gas prices affect the economics of coal generation?

A. Low natural gas prices are detrimental to coal generation in two critical ways: 1) lower gas prices lead to lower wholesale market electricity prices, making market purchases more attractive relative to the costs of coal generation; and 2) operating natural gas generation becomes more competitive with a lower fuel cost, thus it is more likely to displace coal generation. It is, therefore, not surprising that the Company's low gas price outlook in the 2012 IRP disfavored the Four Corners Units 4 and 5 acquisition. In its 2012 IRP, the Company stated that "natural gas prices exerted the largest impact on the portfolio results of all of the sensitivities analyzed by APS."[27]

Q. How has the Company's outlook of gas prices changed since its 2012 IRP?

A. The Company's forecasts of natural gas prices (shown in Figure 1) have mostly shifted downward since the 2012 IRP and since the Company finalized the acquisition. For instance, the first six years of the Company's 2014 IRP base case forecast closely resembles the 2012 IRP <u>low</u> gas forecast, where the Company had found that passing on the acquisition would save ratepayers substantially.[28]

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[26] 2012 IRP at ATT-30, 48-49.
[27] *Id.* at 61.
[28] *Id.* at ATT-30, 48-49; 2014 IRP at 246.

Subsequent to the 2014 IRP, the Company's forecasts of natural gas prices [redacted]

Figure 1: APS Natural Gas Price Forecasts ($/MMbtu) CONFIDENTIAL[29]

[redacted]

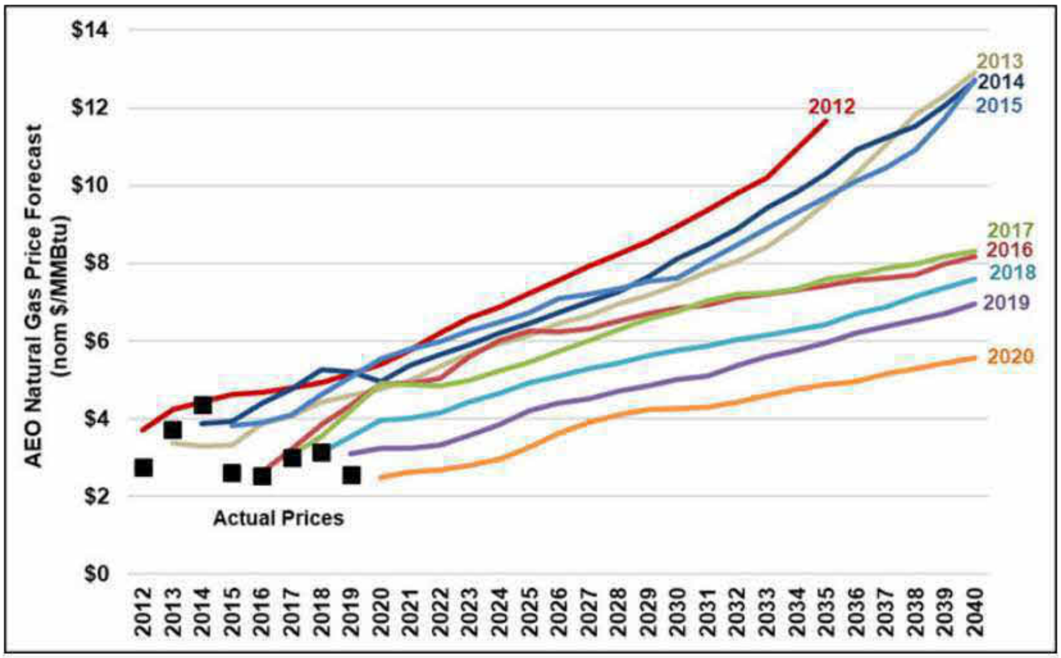
Q. Have industry-wide gas price expectations lowered since 2012?

A. Yes. Since 2012, natural gas price expectations throughout the industry have declined dramatically. Actual gas prices have remained low, especially since 2015, showing that previous predictions overestimated prices. Figure 2 below shows the

[29] 2012 IRP at ATT-30, 137; 2014 IRP at 58, 246; Confidential Attachment "SC 1.23_APS19RC00718_APS 2017 IRP_CONF" at 143, 294 (provided as an attachment to APS Response to SC DR 1.23); Confidential Attachment "SC1.22_ExcelAPS19RC00773_Fuel and Market Price Forecasts_CONF" (referred to in APS Supplemental Response to SC DR 1.22). All confidential discovery responses referenced in this testimony are compiled and available within Attachment TC-3 ["Attach. TC-3"].

Energy Information Administration's (EIA) Annual Energy Outlook (AEO) forecasts since 2012 for Henry Hub natural gas prices along with actual Henry Hub prices.[30]

Figure 2: Annual Energy Outlook (AEO) Natural Gas Price Forecasts ($/MMbtu)[31]



Q. Did the Company re-assess the retirement of Four Corners Units 4 and 5 in its 2014 IRP?

A. No. Such a dramatic change in natural gas price expectations should have led the Company to re-evaluate the units' future. Yet despite the drop in gas price expectations (see Figure 2) which disfavored coal generation, all of its 2014 IRP

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[30] Henry Hub is a commonly-used natural gas price point, located in Louisiana.

[31] U.S. Dep't of Energy, *Annual Energy Outlook 2020: Table 1*, https://www.eia.gov/outlooks/aeo/data/browser/ (last visited July 29, 2020).

portfolios continued to assume that Four Corners Units 4 and 5 would operate until 2038.[32]

B. The Need to Spend More Than $600 Million at Units 4 and 5 Should Have Forced the Company to Reconsider Retirement

Q. Please explain the SCR expenditure related to Four Corners Units 4 and 5.

A. APS and the co-owners were facing a legal requirement to substantially reduce nitrogen oxide (NOx) emissions at Four Corners Units 4 and 5 by July 31, 2018.[33] But the SCR retrofits that achieved such reductions were estimated to cost $635 million ultimately costing $625 million (or $385 million for APS's share).[34] This was a substantial investment in an aging coal plant: APS's share of the SCRs cost was more than $130 million higher than the cost of buying SCE's 48 percent ownership share in the units.[35]

The construction of the SCRs did not begin until September 2015. Around that time, the industry's natural gas price expectations had also dropped again (*see* Figure 2, [redacted] Either one of these factors should have led APS to re-evaluate the units' future. Instead, facing both a major expenditure and lower gas price expectations

[32] 2014 IRP at 55, 231.
[33] ALJ Recommendation at 6:12-18.
[34] *Id.* at 9:16-18.
[35] Decision No. 74876 at 43, Docket No. E-01345A-11-0224 (Ariz. Corp. Comm'n Dec. 23, 2014), *available at* https://docket.images.azcc.gov/0000159386.pdf.
[36] Attach. TC-3, Confidential Attachment "SC 1.22_ExcelAPS19RC00773_Fuel and Market Price Forecasts_CONF" (referred to in APS Supplemental Response to SC DR 1.22). [redacted] *Id.* at tab "2015".

from the industry, the Company failed to re-evaluate the decision to spend more than $600 million at the plant.

Q. Leading up to the more than $600 million spending on SCRs at the units, did the Company re-evaluate this major investment compared to retiring the units?

A. No. The Company stated that it did not conduct "any forward-looking economic analysis of either or both of Four Corners Units 4 and 5 since the SCR project began in early 2014."[37] Faced with a major investment at a generating unit, prudent planning requires that owner(s) to consider whether the investment is cost-effective relative to other options—such as retiring the units. Indeed, many coal generators have retired or converted to gas in the past decade in lieu of making major investments.[38]

Q. Does the Company claim to be responsible for re-evaluating the SCR decision?

A. No. The Company appears to believe that the issue of the SCR investment is settled. It claims that the prudence of the SCRs was decided by the Commission when it

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[37] Attach. TC-2, APS Supplemental Response to Sierra Club DR 1.26(c).

[38] *See, e.g.,* U.S. EPA, Response to Muskogee Letter (Feb. 5, 2019) *available at* https://www.epa.gov/sites/production/files/2019-02/documents/muskogee_generating_station_petition_response_final_2-5-19.pdf) (regarding Muskogee Units 4 and 5 in Oklahoma in 2019); Press Release, Brandon Davis-Handy, Indianapolis Power & Light Company, *IPL Receives Approval for Plans to Stop Burning Coal at Hardin Street Station Unit #7* (July 29, 2015), *available at* https://www.iplpower.com/About_IPL/Newsroom/News_archives/2015/IPL_receives_approval_for_plans_to_stop_burning_coal_at_Harding_Street_Station_Unit__7/ (regarding Harding Street Unit 7 in Indiana in 2016); *AEP to Retire Big Sandy Coal-fired Unit 2*, Power Engineering, Dec 19, 2012, *available at* https://www.power-eng.com/2012/12/19/aep-to-retire-big-sandy-coal-fired-unit-2/ (regarding Big Sandy Unit 2 in Kentucky in 2015).

approved the SCE acquisition in December of 2014.[39] It also cited to the ALJ's finding that the SCRs were "completed in a reasonable, cost-efficient, and prudent manner."[40]

Q. Do you agree that the prudency of the SCRs has been decided?

A. No. The Commission has not issued an order on the prudence of the SCR costs, and those costs are currently not included in rates. But even if the investments were deemed prudent by the Commission in 2014, that did not remove the Company's obligation to re-evaluate the decision with up-to-date facts on the ground—and it does not obviate the need for continued evaluation of the units' future today.

Q. Was one of the co-owners' spending on the SCRs at Four Corners 4 and 5 found to be imprudent?

A. Yes. The New Mexico Public Regulation Commission (NMPRC) <u>disallowed</u> the Public Service Company of New Mexico's (PNM) rate of return on the SCR and other capital costs.[41] The NMPRC found "that PNM's imprudence extended not just to the decision to install SCR and make additional investments in FCPP [Four Corners Power Plant], but to PNM's determination that continued use of FCPP as base load generation was necessary."[42] The NMPRC concluded that PNM's analysis:

[39] Attach. TC-2, APS Supplemental Response to Sierra Club DR 1.26(a).
[40] *Id.*
[41] Order Partially Adopting Certification of Stipulation at 20, Docket No. 16-00276-UT (N.M. Public Reg. Comm'n Dec. 20, 2017), *available at* https://edocket.nmprc.state.nm.us/AspSoft/HandlerDocument.ashx?document_id=1164794.
[42] *Id.*

> …omitted at a minimum intervening changes in the market prices for alternatives such as gas, solar and wind. PNM also ignored other developments during this period that would have triggered a prudent utility to update and review its prior analysis, including the withdrawal of FCPP co-owner E1 Paso Electric Company (EPE) from participation at FCPP announced in November 2013, an increase in the cost estimates for the SCR project as well as a significant decline in the performance of FCPP as evidenced in a significant rise in the forced outage rate that prompted concerns by other FCPP co-owners.[43]

As a result of finding imprudence, the NMPRC discussed the possibility of further disallowances in a later rate case, concluding that only disallowing the rate of return on (but not the "return of" or depreciation) the SCR expenditure may be insufficient. The Commission referred to this as a "limited remedy" and that the "propriety of additional disallowances should be addressed" in a future docket.[44] Thus, the NMPRC made it clear that the issue of imprudence of the SCR investment, and additional expenditures related to the continued operations of the two units, is not resolved. (As of this writing, PNM has not filed a subsequent rate case.)

Q. Did APS reevaluate the SCR investment once construction had started?

A. No.

Q. Once construction of a major project has already started, does that obviate the utility's responsibility to evaluate its cost-effectiveness?

A. No. The Company had a continuing obligation to re-assess these major investments even after construction was underway. Merchant operators commonly evaluate

[43] *Id.* at 16-17.
[44] *Id.* at 20.

investments on a forward-going basis to re-assess their assets' future. For instance, in 2015, Dynegy, then the owner of the Newton coal plant in Illinois, planned to install an FGD (flue gas desulfurization) at the plant for $186 million to be completed in 2019.[45] However, Dynegy stopped the project in September 2016 and decided to retire one of the units, after it had already spent $148 million on the FGD.[46] Thus, the owner decided that abandoning the FGD project, even though most of the budget had been spent, was the best option for the company and its shareholders. Similarly, a regulated utility like APS has a continuing obligation to pursue low-cost, low-risk planning for its ratepayers. This obligation does not cease once a construction project is underway.

Q. In the 2017 IRP, did the Company assess retirement of Four Corners Units 4 and 5 in 2031 instead of 2038?

A. Yes. The 2017 IRP included one portfolio ("Carbon Reduction") that assumed that the units retired in 2031; the other six portfolios assumed that the units would retire in 2038.[47] The one portfolio that assumed 2031 retirement was the lowest cost but was not selected as the Company's preferred plan.[48]

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[45] Dynegy Inc., 2016 Annual Report (Form 10-K) at F-40 (Feb. 25, 2016), a*vailable at* https://www.sec.gov/Archives/edgar/data/1379895/000137989516000022/dyn-20151231_10k.htm.

[46] Dynegy Inc., 2017 Annual Report (Form 10-K) at 61 (Feb. 24, 2017), *available at* http://www.annualreports.com/HostedData/AnnualReports/PDF/NYSE_DYN_2016.pdf.

[47] 2017 IRP at 13, 259.

[48] *Id*. at 14.

Q. Did the Company's projections of the units' costs and performance change significantly in the 2017 IRP compared to past IRPs?

A. Yes. The Company projected an [redacted] in the costs of owning and operating the units, along with a [redacted] in the units' future generation, and [redacted][49] Despite this [redacted] outlook, the Company still chose a portfolio where the units operated until 2038 and failed to assess any portfolio where they were retired prior to 2031.

To understand this change in the units' outlook over time, I compared the cost and production outlooks presented for the units in APS's 2012, 2014, and 2017 IRPs. For example, APS's projected costs per MWh [redacted] between the 2014 and the 2017 IRPs—shown in Figure 3. Excluding carbon costs, the levelized costs of the units [redacted] between the 2014 and 2017 IRPs. (The levelized cost of carbon [redacted] in both IRPs). The breakdown of the units' costs as projected in the 2012, 2014 and 2017 IRPs is shown in Figure 3 below. For comparison purposes, and relying on APS's own projections, I have calculated the costs of the units across the same time-period (2017 through 2038) and using the same cost measure (levelized costs in 2017 dollars).[50]

[49] Highly Confidential Attachment "SC 1.15_ExcelAPS19RC00883_Generating Unit EAF 2010-2019_HIGHLY CONF" (referred to in APS Supplemental Response to SC DR 1.15(f)). All highly confidential discovery responses referenced in this testimony are compiled and available within Attachment TC-4 ["Attach. TC-4"].

[50] I relied on the following sources from APS: Attach. TC-3, Confidential Attachment "SC 2.1_ExcelAPS19RC01244_12IRP FC Rev Req_CONF" (referred to in APS Supplemental Response to SC DR 2.1(b)); Attach. TC-3, Confidential Attachment "2.1_ExcelAPS19RC01247_14IRP FC Rev Req_CONF" (referred to in APS Supplemental Response to SC 2.1(b)); Attach. TC-3, Confidential Attachment "SC 2.1_ExcelAPS19RC01250_17IRP FC Rev Req_CONF" (referred to in APS Supplemental Response to SC DR 2.1(b)). To calculate the levelized costs, I also used the 2017 IRP

Figure 3: Levelized Costs of Four Corners Units 4 and 5 CONFIDENTIAL ($2017/MWh, 2017-2038)[51]

[redacted]

The [redacted] in levelized costs is in part due to the Company projecting that the units will [redacted]. A [redacted] in generation means that the costs per MWh will [redacted] all else equal, because the same fixed costs will be spread across [redacted] MWh. For 2017 through 2038, the Company projected an average capacity factor of [redacted] in the 2017 IRP, compared to [redacted] in the 2014 IRP. The change in generation was likely due to lower natural gas price expectations (see Figure 2), and because the units would be [redacted] than previously expected. The projected forced outage rate from 2017 through 2019 [redacted] was on average [redacted] in the 2014 IRP.[52]

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discount rate of 7.5% (2017 IRP at 163) and the projections of Four Corners 4 and 5 generation from the Company's preferred portfolio in each IRP.

[51] *Id.*

[52] Attach. TC-3, Confidential Attachment "SC 1.21_ExcelAPS19RC01064_Forecasts for 2012,2014,2016_CONF" at 3 (referred to in APS Supplemental Response to SC DR 1.21).

It is clear that the Company's outlook for the units' performance markedly changed at the time of the 2017 IRP analysis. The units were projected to be [redacted]. Yet the Company failed to consider whether there were lower-cost solutions for ratepayers, like shutting these units down before 2031.

C. <u>Even After a Major Investment Was Completed, Continued Operation of the Units Should Have Been Tested Against Competitively Priced Renewables and Storage Resources</u>

Q. Is it possible that the units were not economic in 2018, after the SCRs were completed?

A. Yes. Although the SCRs were completed, and $625 million had been spent (by all owners) when it requested the SCR rate adjustment in April 2018, the Company could still have re-evaluated the units' long-term future. A forward-looking analysis, looking only at future spending at the units, may have shown that options other than continued operation were less expensive. In other words, re-evaluating the economics in 2018 would have enabled APS to determine whether—in light of dramatic changes in the electricity industry, such as falling gas price forecasts and renewable energy costs—ratepayers would save money by APS shutting down the units, even assuming that ratepayers were required to pay for the return of and on all of APS's preceding expenditures.

Other companies have routinely re-evaluated continued operation of coal units, even following a major capital expenditure. For example, in 2016, PNM (a co-

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Forecasts were provided for September 2011, 2013, and 2016; the Company claims these are the same vintage as the 2012, 2014, 2017 IRP analyses, respectively. Attach. TC-2, APS Supplemental Response to SC DR 1.21(m).

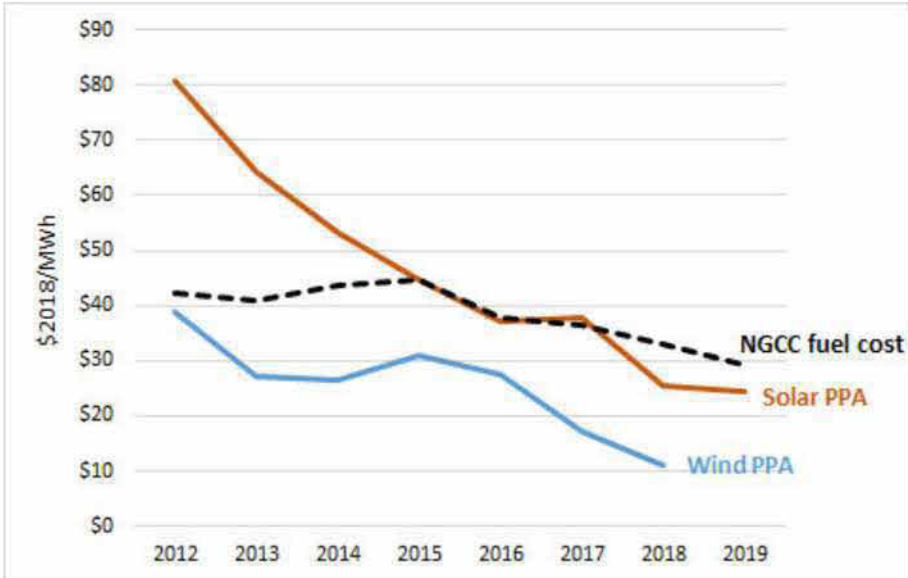
owner of Four Corners) completed the installation of selective non-catalytic reduction (SNCR) and balanced draft technology (BDT) at the San Juan coal plant, costing $78 million.[53] Soon after completing that project, in its 2017 IRP, PNM estimated savings would result from retiring San Juan in 2022 and pursuing natural gas and renewable resources instead.[54] In its filing for approval of replacement resources, PNM concluded that, for San Juan, "there is no economic or practical way for the plant to continue to serve PNM customers past 2022."[55] And as I explained previously, the NMPRC—after disallowing some of PNM's spending on Four Corners' SCRs—discussed the possibility of further prudence disallowances.

Q. Have the costs of renewable resources decreased dramatically in recent years?

A. Yes, particularly for solar photovoltaic (PV) installations. The Lawrence Berkeley National Laboratory ("LBNL") tracks power purchase agreements ("PPAs") for renewable resources across the U.S. In 2019, it found that the generation-weighted average cost of actual solar PV PPAs was $24.40 per MWh in 2019, compared to $80.90 in 2012. Shown below in Figure 4, the study compared the cost of wind and solar PPAs to the 20-year forward, levelized costs of <u>fuel only</u> for a natural gas combined cycle (NGCC) unit.

[53] PNM Resources Inc., 2016 Annual Report (10K Form) at B-87 (Feb. 28, 2017) *available at* https://otp.tools.investis.com/clients/us/pnm_resources/SEC/sec-show.aspx?Type=html&FilingId=11891412&CIK=0001108426&Index=10000.
[54] Direct Testimony of Thomas G. Fallgren at 31-21, Docket No. No. 19-00195-UT (N.M. Public Reg. Comm'n July 1, 2019), *available at* https://edocket.nmprc.state.nm.us/AspSoft/HandlerDocument.ashx?document_id=1179829.
[55] *Id*. at 32:13-14.

Figure 4: LBNL Levelized PV and Wind PPA Prices and Levelized Natural Gas Price Projections ($2018/MWh)[56]



This data shows solar PV as on par with NGCC fuel cost expectations for 2015 through 2017. But in 2018 and 2019, solar PV PPAs were less expensive than forward-going natural gas fuel alone. The same study also shows sharp decreases in solar/battery storage hybrid projects.[57]

Q. Have utilities that recently issued all-resource solicitations found that pursuing renewables and/or storage is lower cost than continuing to operate coal?

A. Yes. In nearby states, utilities have issued all-resource requests for proposal ("RFPs") and found that investing mostly in new renewables and storage is preferred to continued coal operations. Below are two examples:

[56] Mark Bolinger, Joachim Seel & Dana Robson, *Utility-Scale Solar: Empirical Trends in Project Technology, Cost, Performance, and PPA Pricing in the United States –2019 Edition* at 45, Lawrence Berkeley National Laboratory (LBNL) (Dec. 2019), *available at* https://emp.lbl.gov/utility-scale-solar/ (recreated from Excel data provided by the authors).
[57] *Id.* at 42.

First, as mentioned above, in its 2017 IRP, PNM found that retirement of the San Juan coal plant was cheaper than continuing the plant's operations. After this finding, PNM issued an all-source RFP in October 2017 and a subsequent storage-only RFP in April 2019.[58] The all-source RFP resulted in 345 bids, most of which were not made public. However, PNM reported bid prices for two solar/battery hybrid projects: 1) the Arroyo project included 300 MW of solar at $18.65 per MWh paired with 40 MW of battery storage at $7.46 per kW-month capacity charge; and 2) the Jicarilla project included 50 MW of solar at $19.73 per MWh paired with a 20 MW battery at $9.97 per kW-month capacity charge.[59] In total (including those two projects), PNM chose a replacement portfolio that included 350 MW of solar, 130 MW of battery storage, and 280 MW of natural gas.[60] But instead of adopting PNM's portfolio, the Commission approved the "CCAE 1" portfolio—which I and others supported in testimony in that case—which ultimately included 650 MW of solar, 300 MW of battery storage, and no new gas generation.[61]

[58] Direct Testimony of Roger W. Nagel at 13, Docket No. No. 19-00195-UT (N.M. Pub. Reg. Comm'n July 1, 2019), *available at* https://edocket.nmprc.state.nm.us/AspSoft/HandlerDocument.ashx?document_id=1179834.
[59] PNM Consolidated Application for the Abandonment, Financing and Replacement of the San Juan Generating Station Pursuant to the Energy Transition Act at 16, Docket No. 19-00195-UT (N.M. Pub. Reg. Comm'n July 1, 2019), *available at* https://edocket.nmprc.state.nm.us/AspSoft/HandlerDocument.ashx?document_id=1179824.
[60] *Id.* at 6-7.
[61] Order on Recommended Decision on Replacement Resources – Part II at 15, Docket No. 19-00195-UT, (N.M. Pub. Reg. Comm'n July 29, 2020), *available at* https://edocket.nmprc.state.nm.us/AspSoft/HandlerDocument.ashx?document_id=1191982.

Second, Xcel Colorado issued an all-resource RFP in 2017. Xcel's modeling showed that retiring two coal units early, Comanche 1 and 2 in 2022 and 2025 (respectively), and replacing them with mostly wind, solar and gas combustion turbines was lower-cost than continuing the coal units' operations and replacing them later.[62] The utility received 430 bids, over 350 of which were for renewable energy or storage.[63] The results for standalone and combinations of wind, solar and battery resources, showed median bid prices of between $18 and $36 per MWh depending on the type.[64] (Note that because these were median values that half of the bids for each resource type were cheaper, by definition.) The utility ultimately chose a portfolio that included early retirement of the two coal units, and the addition of 1,131 MW of wind, 707 MW of solar, 275 MW of battery and 383 MW of gas.[65]

These examples show how cost-competitive renewable and storage resources have been in recent years compared to both coal and natural gas. Both PNM and Xcel sought a competitive, robust sample of bids and both ultimately advocated early coal retirement combined with mostly renewable and storage replacement resources. Inexplicably, APS has declined to take advantage of the broad, low-cost

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[62] Rebuttal Testimony and Attachments of James F. Hill at 38, Table JFH-12, Docket No. 16A-0396E (Colo. Pub. Utility Comm'n Jan. 29, 2018), *available at* https://www.dora.state.co.us/pls/efi/EFI.Show_Filing?p_session_id=&p_fil=G_740936.
[63] Xcel Energy Colorado, 2017 All Source Solicitation: 30-Day Report at 3, Docket No. 16A-0396E (Colo. Pub. Utility Comm'n Dec. 28, 2017), *available at* https://assets.documentcloud.org/documents/4340162/Xcel-Solicitation-Report.pdf.
[64] *Id*. at 9.
[65] Xcel Energy Colorado, Electric Resource Plan: 120-Day Report at 15, Docket No. 16A-0396E (Colo. Pub. Utility Comm'n June 6, 2018), *available at* https://www.powermag.com/wp-content/uploads/2018/06/xcel-2018-clean-energy-plan.pdf.

market of renewable and storage resources that could cost-effectively replace Four Corners Units 4 and 5 prior to 2031, to the detriment of Arizona ratepayers.

Q. Since it acquired SCE's share in 2013, has APS tested the economics of retiring Four Corners Units 4 and 5 prior to 2031?

A. No. As noted, APS did not incorporate any pre-2038 retirement scenarios in its 2014 IRP. It incorporated one 2031-retirement portfolio into its 2017 IRP, but it did not evaluate a pre-2031 retirement portfolio.[66] APS also failed to present a pre-2031 retirement portfolio in its 2020 IRP.[67]

Q. Please summarize the Company's past resource planning regarding Four Corners Units 4 and 5.

A. Prudent resource planning requires the competition of existing resources along with new, available resource options. If existing resources are not periodically tested against new resource options and ever-changing market conditions, then the utility is failing to prudently manage its units' operations. Since APS acquired SCE's share of ownership in the coal units, natural gas price expectations have decreased, the [redacted], and the costs of renewable and storage resources have sharply declined. Despite conditions that have increasingly disfavored coal operations, the Company has consistently prevented Four Corners Units 4 and 5 to compete under competitive conditions. APS has instead opted to insulate these two coal units from competition, continuing

[66] Attach. TC-2, APS Supplemental Response to SC DR 1.12(a).
[67] *Id.* at APS Supplemental Response to SC DR 1.12(b); 2020 IRP at 18.

investment in the units under a 2031 retirement, and asking for recovery of these costs from ratepayers.

III. FOUR CORNERS UNITS 4 AND 5 WILL CONTINUE TO COST RATEPAYERS SUBSTANTIALLY AND SHOULD BE RETIRED AS SOON AS POSSIBLE

Q. Please summarize your assessment of the going forward costs of Four Corners Units 4 and 5.

A. In this section, I explain my forward-looking economic assessment of the units, comparing retiring units 4 and 5 by the end of 2023 to the Company's current plan to retire them in 2031. I used forecasts APS provided in March 2020 and the Company's recently released 2020 IRP. Under a wide range of assumptions, I find that early retirement of the units would provide substantial savings to ratepayers. For instance, using the Company's 2020 IRP base case, I estimated savings between [redacted] This assessment relied on the Company's projections of the units' fixed and variable costs, as well as costs associated with ending their operations—such as any costs related to termination of the coal contract with the Navajo mine.

Given these results, APS should plan for the early retirement of these units and the Commission should consider my findings before allowing further expenditures at these units into rates, absent specific justifications for individual expenditures. If APS does not agree to retire the units in 2023, the Commission should require that the Company amend its 2020 IRP to include an evaluation of 2023 retirement (or a retirement as soon thereafter as possible). As noted, I may provide additional testimony on this topic following APS's response to Chairman Burns' September 1, 2020 letter.

Q. How did you choose the end of 2023 as an appropriate retirement date?

A. Retiring the units in 2023 is appropriate for a number of reasons. Although immediate retirement would likely result in more cost savings for ratepayers, I recognize that the Company cannot retire the units immediately. APS has various obligations, including to serve customers in the units' absence by procuring replacement energy and capacity, as needed, and to honor contracts with other parties. For instance, the owners of the units signed a coal contract with NTEC which provides fuel for the units through 2031.[68] However, APS stated that it could terminate its participation in that contract with 24 months' notice.[69] A retirement date for the end of 2023 would give APS more than 3 years (39 months) as of this filing to coordinate the units' retirement, exit the coal contract, and procure replacement resources.

Q. Please describe the costs related to retiring unit 4 and 5 that you considered for both 2023 and 2031 retirement scenarios.

A. Costs for ceasing the units' operations fall into three broad categories: costs that are "avoidable," "unavoidable," or "incremental" with early retirement.[70]

Avoidable costs are those that would be saved if the units retired early. I include the following avoidable costs that must be incurred if the units operate until 2031, but <u>not</u> if they retire in 2023:

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[68] Ariz. Pub. Serv. Application at 163, Schedule E-9, Docket No. E-01345A-19-0236 (Nov. 11, 2019), *available at* https://docket.images.azcc.gov/E000003517.pdf.

[69] Attach. TC-2, APS Response to SC DR 2.3(f)(iii) (the un-redacted version of APS Response to SC DR 2.3 is included in Attach. TC-4).

[70] These three categories are also used by Consumers Energy in Michigan.

- Fuel, variable O&M, fixed O&M, and capital spending at the units from 2024 through 2031.[71]
- Performance bond costs at the Navajo Mine from 2024 through 2031.[72]
- Other coal contract costs required from 2024 through 2031.[73]

Unavoidable costs are those could be incurred regardless of the units' retirement date. Because these could be incurred in both retirement years, there was no need to include them in my analysis. Therefore, for both the 2023 and 2031 retirement years, I did not include:

- Capital costs invested in the units through 2023, such as the SCRs.[74]
- Fuel, variable O&M, fixed O&M, and capital spending at the units through 2023.
- Final cleanup costs related to the Four Corners units or any other legally-required environmental closure costs.

[71] Note that Attachment TC-4, Highly Confidential Attachment "SC 1.16_ExcelAPS19RC00885_ Unit ALL_Highly CONF" (referred to in APS Supplemental Response to SC DR 1.16) provides future fuel, variable O&M, and generation costs. Attachment TC-4, Highly Confidential Attachment "SC 1.16_ExcelAPS19RC00884A_ Plant FIXED_Highly CONF" (referred to in APS Second Supplemental Response to SC DR 1.16) and Attachment TC-4, Highly Confidential Attachment "SC 2.5_ExcelAPS19RC01226_Fixed Fuel and O&M Costs_HIGHLY CONF" (referred to in APS Response to SC DR 2.5(a)) provide forecasts of fixed costs. [redacted] For my analysis, I assumed the [redacted]

[72] The Company's response to Sierra Club Discovery Request 3.1(a) states that performance bond costs are avoidable if APS terminates the coal contract with two years notice (the un-redacted version of APS Response to SC DR 3.1is included in Attachment TC-3).

[73] Attach. TC-2, APS Response to SC DR 3.1(a)(i) (the un-redacted version of APS Response to SC DR 3.1is included in Attachment TC-3).

[74] Note that even if there were a disallowance for past investments, such as the SCRs, then any remaining, allowed cost would still be unavoidable and identical in both retirement years.

- Final reclamation costs at the Navajo Mine.[75]
- The lease with the Navajo Nation.[76]

Incremental costs are those costs directly associated with terminating the coal contract before it ends in 2031. Specifically, if the co-owners terminated the contract before it expired, they would be required to pay for termination costs associated with the mine. These costs are higher if the units retire early and the contract is terminated prior to 2031. The Company provided stranded costs for termination dates of July 1 of each year from 2020 through 2031. I included the following for each retirement date:

- For end of 2023 retirement, I assumed the July 1, 2023 termination cost of $39.1 million provided by APS.[77]
- For 2031 retirement, I assumed no termination cost.[78]

Q. Please describe the costs of replacement resources you used in your analysis.

A. I did not specify the type of replacement resources but instead modeled a generic replacement resource using a wide range of costs from $30 per MWh to $50 per MWh (levelized $2024). I then assumed that APS's projections of the units' generation from 2024 through 2031 would be completely replaced—assuming a 2 percent annual escalation rate for the replacement cost. The initial range of costs

[75] Blankenship Direct at 30:8-18.
[76] Attach. TC-2, APS Response to SC DR 1.4(j) states that APS has no way to terminate the lease early and that lease payments are locked in through 2031.
[77] Attach. TC-2, APS Response to SC DR 3.1(d) (the un-redacted version of APS Response to SC DR 3.1 is included in Attachment TC-3).
[78] *Id.* The Company indicated in response to Sierra Club Data Request 3.1(d) that there was a termination cost with July 2031 retirement of $12.8 million. However, to be conservative in favor of a 2031 retirement, I assumed that there would be no termination cost if the units operated through 2031.

skew high compared to all-source RFP bids received by nearby utilities for coal replacement (as discussed previously) in recent years. Nevertheless, I also calculated a "breakeven" replacement cost at which 2023 and 2031 retirement would be equal. If APS were to procure replacement resources (including a portfolio of replacement resources) at any cost below this "breakeven" level, a 2023 retirement and replacement would provide savings compared to operation through 2031.

Q. What are your findings regarding early retirement and replacement of Four Corners Units 4 and 5 based on the forecasts APS provided in March 2020?

A. My findings demonstrate APS's customers would save money if Four Corners retired in 2023 rather than 2031. I estimate that the savings are substantial, using low, mid, and high replacement costs of $30, $40, and $50 per MWh (respectively). Here, I relied on forecasts that APS provided to Sierra Club in March 2020 and produced "between the third quarter of 2016 and the third quarter of 2019."[79] The results, shown in Figure 5, include:

- At low replacement costs of $30 per MWh, the savings from 2023 retirement are nearly [redacted] NPV (2024 through 2031)
- At mid replacement costs of $40 per MWh, the savings from 2023 are [redacted] NPV (2024 through 2031)
- At high replacement costs of $50 per MWh, the savings from 2023 are over [redacted] NPV (2024 through 2031)

[79] Attach. TC-2, APS Response to SC DR 6.1(a).

Figure 5: Cumulative Savings from 2023 Retirement of Four Corners 4 and 5 ($2023 NPV mil) HIGHLY CONFIDENTIAL[80]

[redacted]

Q. Would customer savings occur immediately after 2023 retirement?

A. Yes, if the Company procured PPA replacements in this $30-$50 per MWh range, then the savings would be immediate. In 2024, the annual savings would range from [redacted]—shown in Figure 6—and the annual savings would escalate through 2030. Savings in 2031 are lower because APS assumes that the [redacted][81]

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[80] *See supra* note 71; Attach. TC-3, Confidential Attachment "SC 2.3_APS19RC01236_FC Coal Cost Information and Forecasts_CONF" (referred to in APS Response to SC DR 2.3(d)(ii)) (the un-redacted version of APS Response to SC DR 2.3 is included in Attach. TC-4); Attach. TC-2, Attachment "SC 2.3_ExcelAPS19RC01224_Sellers Stranded Costs" (referred to in APS Supplemental Response to SC DR 2.3(f)(ii)) (the un-redacted version of APS Response to SC DR 2.3 is included in Attach. TC-4); Attach. TC-2, APS Response to SC DR 6.4(b).

[81] Attach. TC-4, Highly Confidential Attachment "SC 1.16_ExcelAPS19RC00885_ Unit ALL_Highly CONF" (referred to in APS Supplemental Response to SC DR 1.16).

Figure 6: Annual Savings from 2023 Retirement of Four Corners 4 and 5 ($mil) HIGHLY CONFIDENTIAL[82]

[redacted]

Q. What is the "breakeven" replacement cost at which the costs of 2023 and 2031 retirement would be the same?

A. A replacement cost of [redacted] per MWh in 2024 (escalating at 2 percent annually) would be a "break even" point. Replacement costs below this level would produce savings from earlier retirement.

Q. Is it possible your analysis above actually underestimated savings?

A. Yes. Several of my assumptions were deliberately conservative (i.e., favorable to a 2031 retirement), including:

[82] *See supra* note 80.

- The forecasts of variable costs from APS did not include [redacted] The addition of [redacted] would increase the units' costs and thus increase savings from their retirement.
- I assumed the units would operate through December of 2023, but if it were feasible to retire the units earlier then there would be additional savings in 2023 that are not currently captured.
- I assumed APS would incur the same capital costs through 2023 whether the units retire at the end of that year or in 2031. But if APS planned for 2023 retirement, it is likely capital spending leading up to that date could be avoided. Savings from these avoided costs were not included in my analysis.
- I assumed that the units would operate at the level projected by APS. In the event that the units generated less energy—which could result from a variety of factors like lower-than-forecasted customer load, higher forced outages, carbon costs, or lower-than-anticipated gas prices—then the savings would be higher because there would be less replacement energy needed.

Q. Did you also conduct a forward-looking assessment using the Company's 2020 IRP modeling?

A. Yes. The analysis above was based on the information the Company provided for the most recent forecasts of Four Corners costs at the time of the data request.[83] The

[83] *See supra* note 70.

Company provided the data in early March 2020. Subsequently, the Company filed its 2020 IRP on June 26, 2020. As a check against the savings estimates above, I also evaluated retirement of the two units using the Company's 2020 IRP forecasts.

Q. Did the analysis of the Company's 2020 IRP modeling change your conclusions about Four Corners Units 4 and 5?

A. No. The IRP analysis reinforced my conclusion that the units should be retired. In the 2020 IRP, the Company modeled three carbon cost sensitivities starting in 2025: high, base, and no carbon cost.[84] It also modeled three portfolios that represented the approach to moving towards clean energy: Bridge, Shift, and Accelerate. In all three portfolios, Four Corners operates through 2031.[85] I used the Company's forecasts for the Bridge portfolio under its three carbon cost sensitivities.[86] The treatment of avoidable, unavoidable, and incremental costs remains consistent with what I described above.

The resulting savings from 2023 retirement of Four Corners 4 and 5 are shown below in Table 1. In the Bridge portfolio under the Company's 2020 IRP base case scenario, the savings from retiring the units by end-of-year 2023 was between [redacted] more than [redacted] than the savings I had estimated using the March 2020 forecasts provided in this proceeding. In addition to this "base case," which incorporated a base carbon cost, APS's 2020 IRP also

[84] 2020 IRP at 147.
[85] *Id*. at 18.
[86] The Company did not choose a preferred portfolio. I chose the Bridge portfolio to be conservative (favorable to Four Corners operating through 2031), as it had the lowest amount of carbon reduction of the three portfolios. [redacted]

evaluated "high carbon" and "no carbon" cases. Not surprisingly, a higher carbon cost would lead to higher retirement savings and, conversely, a lower carbon cost would lead to lower savings. The "breakeven" replacement cost using the 2020 IRP is between [redacted] and [redacted] per MWh. The average savings across the nine 2020 IRP combinations of replacement costs and carbon costs is [redacted].

Table 1: Cumulative Savings from 2023 Retirement of Four Corners 4 and 5 ($2023 NPV mil) HIGHLY CONFIDENTIAL[87]

	2020 IRP Bridge (high carbon)	2020 IRP Bridge (base carbon)	2020 IRP Bridge (no carbon)	APS March 2020 (no carbon)
Savings with $30/MWh replacement ($mil)	[redacted]	[redacted]	[redacted]	[redacted]
Savings with $40/MWh replacement ($mil)	[redacted]	[redacted]	[redacted]	[redacted]
Savings with $50/MWh replacement ($mil)	[redacted]	[redacted]	[redacted]	[redacted]
Breakeven replacement cost ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]

Q. Is it likely that the 2020 IRP savings estimates are too low?

A. Yes. The forecasts of fixed O&M for the two units are [redacted] in the 2020 IRP, compared to past IRPs and the forecasts provided in this case in March 2020.

[87] I relied on the following spreadsheets in my analysis: Highly Confidential Attachment "2.12_ExcelAPS19RC01442_Bridge-Base Output files_HIGHLY CONF" (referred to in APS Response to Citizen Groups DR 2.12); Highly Confidential Attachment "2.12_ExcelAPS19RC01743_APS 2020 IRP Carbon Sensitivity Bridge-High Carbon_HIGHLY CONF" (referred to in APS Response to Citizen Groups DR 2.12); Highly Confidential Attachment "2.12_ExcelAPS19RC01744_APS 2020 IRP Carbon Sensitivity Bridge-Low Carbon_HIGHLY CONF" (referred to in APS Response to Citizen Groups DR 2.12) (Sierra Club will not be providing the 2.12 attachments due to the confidential nature and volume of the documents. The spreadsheets are available on the case Sharepoint site pursuant with the protective agreement.); Attach. TC-4, Highly Confidential Attachment "Citizen Groups 2.14_ExcelAPS19RC01446_FC CAPEX_HIGHLY CONF" (referred to in APS Response to Citizen Groups DR 2.14);

Figure 7 shows the Company's various forecasts of fixed O&M. This shows that the March 2020 forecast is [redacted] with forecasts in the previous three IRPs (2012, 2014 and 2017) yet the 2020 IRP forecast is [redacted]

Figure 7: Four Corners Units 4 and 5 Fixed O&M ($mil) HIGHLY CONFIDENTIAL[88]

[redacted]

CAPEX_HIGHLY CONF" (referred to in APS Response to Citizen Groups DR 2.14); Attach. TC-3, Confidential Attachment "SC 6.4_ExcelAPS19RC01807_Bridge_Base_CONF" (referred to in APS Response to Sierra Club DR 6.4); Attach. TC-2, APS response to SC DR 6.4(b); Attach. TC-3, Confidential Attachment "SC 2.3_APS19RC01236_FC Coal Cost Information and Forecasts_CONF" (referred to in APS Response to SC DR 2.3(d)(ii)) (the un-redacted version of APS Response to SC DR 2.3 is included in Attach. TC-4); Attach. TC-2, Attachment "SC 2.3_ExcelAPS19RC01224_Sellers Stranded Costs" (referred to in APS Response to SC DR 2.3(f)(ii)) (the un-redacted version of APS Response to SC DR 2.3 is included in Attach. TC-4).

[88] Attach. TC-3, Confidential Attachment "SC 2.1_ExcelAPS19RC01244_12IRP FC Rev Req_CONF" (referred to in APS Supplemental Response to SC DR 2.1(b)); Attach. TC-3, Confidential Attachment "2.1_ExcelAPS19RC01247_14IRP FC Rev Req_CONF" (referred to in APS Supplemental Response to SC DR 2.1(b)); Attach. TC-3, Confidential Attachment "SC 2.1_ExcelAPS19RC01250_17IRP FC Rev Req_CONF (referred to in APS Supplemental Response to SC DR 2.1(b)); Attach. TC-3, Confidential Attachment "SC 6.4_ExcelAPS19RC01807 _Bridge _Base_CONF" (provided as an attachment to APS Response to SC DR 6.4); Attach. TC-4, Highly Confidential Attachment "SC

Q. Did you conduct a sensitivity analysis of the 2020 IRP savings estimates using fixed O&M from March 2020?

A. Yes. Substituting the March 2020 fixed O&M, which is [redacted] with past IRP forecasts, the retirement savings estimates using the 2020 IRP forecasts would increase by [redacted] across the board. The IRP results, updated with the March 2020 fixed O&M estimate, are shown below in Table 2. After this substitution, my original savings estimates (using all March 2020 forecasts) and the 2020 IRP, no carbon sensitivity are similar. These savings estimates range from [redacted] And as noted above, the savings increase with increasing carbon cost assumptions in the base case and high carbon cases. Using the Company's 2020 IRP base case and comparing across the results in Tables 1 and 2, I estimate savings between [redacted] (with the $50/MWh replacement and 2020 IRP fixed O&M) and [redacted] (with the $30/MWh replacement and March 2020 fixed O&M).

2.5_ExcelAPS19RC01226_Fixed Fuel and O&M Costs_HIGHLY CONF" (referred to in APS Response to SC DR 2.5(a)).

Table 2: Cumulative Savings from 2023 Retirement of Four Corners 4 and 5, using APS March 2020 Fixed O&M Forecast ($2023 NPV mil) HIGHLY CONFIDENTIAL[89]

	2020 IRP Bridge (high carbon)	2020 IRP Bridge (base carbon)	2020 IRP Bridge (no carbon)	APS March 2020 (no carbon)
Savings with $30/MWh replacement ($mil)	[redacted]	[redacted]	[redacted]	[redacted]
Savings with $40/MWh replacement ($mil)	[redacted]	[redacted]	[redacted]	[redacted]
Savings with $50/MWh replacement ($mil)	[redacted]	[redacted]	[redacted]	[redacted]
Breakeven replacement cost ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]

Q. Is the fact that a 2023 retirement results in customer savings sensitive to key inputs?

A. No. While the magnitude of the savings changes depending on the factors outlined above, all of my calculations show substantial savings from 2023 retirement regardless of the chosen assumptions for replacement costs, carbon costs, and fixed O&M costs.

IV. CONCLUSIONS AND RECOMMENDATIONS

Q. What do you conclude from your analysis of Four Corners Units 4 and 5?

A. The Company has continually failed to adequately assess these units' future no matter the underlying market conditions that they face. Since acquiring a larger share of the units in 2013, gas price forecasts have decreased and remain low; and

[89] *See supra* note 87; Attach. TC-4, Highly Confidential Attachment "SC 2.5_ExcelAPS19RC01226_Fixed Fuel and O&M Costs_HIGHLY CONF" (referred to in APS Response to SC DR 2.5(a)).

renewable and storage resources have become low-cost options compared with continued coal operation. The Company also spent hundreds of millions on SCR retrofits, without considering foregoing such spending and retiring the units prior to 2031.

While I am not recommending disallowances for expenditures before the current test year, APS's conduct at prior decision points establishes a clear pattern of failing to prudently evaluate ongoing operations at Four Corners Units 4 and 5 on the part of APS. Most importantly, the Company has yet to look at retiring the units prior to 2031 in the face of mounting evidence that these units are losing APS's customers money.

In place of an analysis by APS, I conducted my own forward-looking economic assessment of the units, relying on APS's own projections of the coal units' costs, and I have found that there would be substantial savings from retiring units 4 and 5 in 2023 instead of 2031, ranging from [redacted] These findings show that the units should be retired as soon as possible. If APS does not decide to retire the units, the Commission should require that the Company evaluate earlier retirement in the 2020 IRP and subsequent IRPs. Accordingly, it is clear that continued investment in and operation of Four Corners Units 4 and 5 beyond 2023 is an imprudent use of resources that should not be carried by ratepayers.

Q. How do you recommend that APS and the Commission address test year and future capital spending at Four Corners Units 4 and 5?

A. There may be planned capital spending included in the revenue requirement for this rate case that would have been unnecessary if APS had prudently evaluated retiring the units before 2031.[90] APS had ample evidence showing that the economics of the units were eroding, well before this rate case. Given the evidence that early retirement of these units would provide substantial savings, a prudent utility would have re-evaluated the long-term operations of the units and modified its planned capital projects accordingly.

It would be unfair and unreasonable to require customers to pay for those capital costs that should have been avoided. However, I am not currently in a position to identify particular projects that could have been avoided during the test year or could be avoided moving forward; rather, APS, as the plant operator, is in the best position to do so. Yet, as of this filing, the Company has refused to provide such an evaluation when asked.[91] Notably, APS's 2020 IRP projects a [redacted] when the plant is assumed to retire in 2031; it is therefore likely that a [redacted] if there were a 2023 retirement.[92] Therefore, the Commission should direct APS to identify such avoidable spending during the test year and

[90] As noted, for Four Corners 4 and 5 specifically, Exhibit BDL-4DR includes $10.1 million in "total projected costs"; Exhibit BDL-5DR includes $58.9 million in "total projected costs."
[91] Attach. TC-2, APS Response to SC DR 7.1.
[92] Attach. TC-4, Highly Confidential Attachment "Citizen Groups 2.14_ExcelAPS19RC01446_FC CAPEX_HIGHLY CONF" (referred to in APS Response to Citizen Groups DR 2.14).

moving forward, and hold this rate proceeding open until such as time as the Commission and other parties are able to review such an evaluation. All avoidable costs should be disallowed from rates.

Q. How do you recommend that APS and the Commission address replacement for these units should they retire?

A. The Commission should direct APS to issue an all-source RFP with the intention of fulfilling its energy and capacity needs in the absence of its share in Four Corners Units 4 and 5, for an in-service date of no later than the end of 2023. In order to encourage a robust, competitive sample of bids, the RFP process should involve: 1) ample time for response from bidders—e.g. more than one month; 2) no preference for technology type, size of project, or ownership; and 3) an independent evaluator. Two examples of all-source RFP's that successfully garnered competitive and robust bids were discussed previously in this testimony: Xcel Colorado and PNM.

The Commission should open a docket to address this replacement process so that stakeholders can be involved in the development of the RFP, choice of independent evaluator, and selection of replacement resources.

Even if the Commission disagrees that Units 4 and 5 should be retired in 2023, then it should still direct the Company to issue an all-source RFP described above to evaluate the units' future. Bids from this RFP could then be modeled to compete with existing APS units, such as Four Corners Units 4 and 5.

Q. Does this conclude your testimony?

A. Yes.

Attachment TC-1

Resume of Tyler Comings

Tyler Comings, Senior Researcher
1012 Massachusetts Avenue, Arlington MA 02476 ꕤ tyler.comings@aeclinic.org ꕤ 617-863-0139

PROFESSIONAL EXPERIENCE

Applied Economics Clinic, Arlington, MA. Senior Researcher, June 2017 – Present.

Provides technical expertise on electric utility regulation, energy markets, and energy policy. Clients are primarily public service organizations working on topics related to the environment, consumer rights, the energy sector, and community equity.

Synapse Energy Economics Inc., Cambridge, MA. Senior Associate, July 2014 – June 2017, Associate, July 2011 – July 2014.

Provided expert testimony and reports on energy system planning, coal plant economics and economic impacts. Performed benefit-cost analyses and research on energy and environmental issues.

Ideas42, Boston, MA. Senior Associate, 2010 – 2011.

Organized studies analyzing behavior of consumers regarding finances, working with top researchers in behavioral economics. Managed studies of mortgage default mitigation and case studies of financial innovations in developing countries.

Economic Development Research Group Inc., Boston, MA. Research Analyst, Economic Consultant, 2005 – 2010.

Performed economic impact modeling and benefit-cost analyses using IMPLAN and REMI for transportation and renewable energy projects, including support for Federal stimulus applications. Developed a unique web-tool for the National Academy of Sciences on linkages between economic development and transportation.

Harmon Law Offices, LLC., Newton, MA. Billing Coordinator, Accounting Liaison, 2002 – 2005.

Allocated IOLTA and Escrow funds, performed bank reconciliation and accounts receivable. Projected legal fees and costs.

Massachusetts Department of Public Health, Boston, MA. Data Analyst (contract), 2002.

Designed statistical programs using SAS based on data from health-related surveys. Extrapolated trends in health awareness and developed benchmarks for performance of clinics for a statewide assessment.

EDUCATION

Tufts University, Medford, MA

Master of Arts in Economics, 2007

Boston University, Boston, MA

Bachelor of Arts in Mathematics and Economics, Cum Laude, Dean's Scholar, 2002.

AFFILIATIONS

Society of Utility and Regulatory Financial Analysts (SURFA)

Member

Global Development and Environment Institute, Tufts University, Medford, MA.
Visiting Scholar, 2017 – Present

CERTIFICATIONS

Certified Rate of Return Analyst (CRRA), professional designation by Society of Utility and Regulatory Financial Analysts (SURFA)

PAPERS AND REPORTS

Woods, B., E. A. Stanton, T. Comings, and E. Tavares. 2019. *Emission Reduction Synergies for Massachusetts Community Choice Energy Programs, Heat Pumps and Electric Vehicles*. Applied Economics Clinic. Prepared for Green Energy Consumers Alliance. [Online]

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Comings, T. 2017. *Testimony on the economics of the proposed acquisition of the Pleasants plant*. Testimony to the West Virginia Public Service Commission, Case No. 17-0296-E-PC. [Online]

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Resume dated August 2020

Attachment TC-2

Public Discovery Responses

Confidential and Highly Confidential
Information has been redacted.

Public APS Responses to Data Requests:

1. APS Response to SC DR 1.4
2. APS Supplemental Response to SC DR 1.12
3. APS Supplemental Response to 1.16
4. APS Second Supplemental Response to SC DR 1.16
5. APS Response to SC DR 1.17
6. APS Supplemental Response to SC DR 1.21
7. APS Supplemental response to SC DR 1.22
8. APS Response to SC DR 1.23
9. APS Supplemental Response to SC DR 1.26
10. APS Response to SC DR 1.27
11. APS Supplemental Response to SC DR 2.1
12. APS Response to SC DR 2.3 (Redacted)
13. Attachment "SC 2.3_ExcelAPS19RC01224_Sellers Stranded Costs" (referred to in APS Response to SC DR 2.3(f)(ii))
14. APS Response to SC DR 3.1 (Redacted)
15. APS Response to SC DR 6.1
16. APS Response to SC DR 6.4
17. APS Response to SC DR 7.1
18. APS Response to Citizen Groups DR 2.12
19. APS Response to Citizen Groups DR 2.14

SC 1.4: For each of the Four Corners units 1 through 5, please provide the following information:

a. Identify the currently applicable coal fuel supply contract(s), including the supplier for such contracts. Please provide copies of each contract.

b. Identify the term of any currently applicable coal fuel supply contract (i.e. length of the contract until expiration or option to renew).

c. Indicate whether the coal fuel supply contract includes any minimum take provisions.

d. Indicate liquidated damages for each year, and how these are calculated.

e. For each minimum take provision identified in (c), please provide:

    i. The minimum annual tons required to be purchased,

    ii. The cost to the Company for not meeting such minimum take requirements (either on a dollar/ton basis or as liquidated damages, or both), and

    iii. The conditions, if any, under which the Company is relieved of its obligations to take the minimum amount of coal specified in the contract.

f. A copy of the lease.

g. Annual lease payments made by APS since the start of the lease.

h. Projections of lease payments through the end of the lease.

i. Analyses conducted by or for APS used to justify extension of the lease.

j. Indicate damages that would be paid for early exit from the lease and how such damages are calculated.

k. Does the Company have plans to modify the Four

SC 1.4 (continued):

Corners units such that they will have lower minimum output levels?

i. If so, explain those plans, and identify the new minimum operating levels that each unit will have following such modifications.

l. For each Four Corners unit, identify the current maximum 1-hour ramp rate.

m. For each Four Corners unit, identify the current maximum 5-minute ramp rate.

n. Does the Company have plans to modify the Four Corners units such that they will have higher maximum ramp rates?

i. If so, explain those plans, and identify the new maximum ramp rates that each unit will have following such modifications.

o. Within the past 30 years, has APS encountered any extreme weather or natural gas infrastructure interruption events that have been mitigated by the existence of coal units with on-site fuel inventory?

i. If so, identify all such events and explain the role played by coal units with on-site fuel inventory.

Response: Subject to and without waiving the objection(s) below, APS will provide responsive information.

Please note that some of this information may only be provided upon execution of a Protective Agreement because the information is either Confidential or Highly Confidential. APS will provide this responsive information upon execution of a Protective Agreement.

With regard to subpart (i), APS objects to this request to the extent that it seeks information regarding the prudency of the Four Corners Power Plant. The discovery sought is neither relevant nor reasonably calculated to lead to admissible evidence for any party's claim or defense. The prudency of the continued operation of the Plant was litigated and conclusively decided in prior Commission decisions in which the Sierra Club participated. This matter is not

Response to SC 1.4 (continued):	the appropriate mechanism for seeking to reopen and modify final Commission decisions under Arizona law.
Supplemental Response:	a. The current Coal Supply Agreement (CSA) is attached as APS19RC00886, effective as of July 1, 2018. This agreement is between the Navajo Transitional Energy Company, LLC and the non-NTEC participant buyers of the Four Corners Generating Station coal (APS, TEP, SRP and PNM). The agreement is Highly Confidential and is being provided pursuant to an executed Protective Agreement in this docket.

b. The term on the CSA is from July 1, 2018 – July 6, 2031.

c. Please refer to Section 4.5 of the CSA provided in part a.

d. Please refer to Section 5 of the CSA provided in part a.

e. Please refer to Sections 5 and 20 of the CSA provided in part a.

f. Please see attachments APS19RC00871 through APS19RC00875 for the entire lease agreement.

g. Please see summary in attachment ExcelAPS19RC00870.

h. Please see summary in attachment ExcelAPS19RC00870.

i. Please see APS's objection above.

j. There are no damages, however, there are no "out" provisions either. APS is required to pay the rent payments through the end of the lease.

k. APS has recently explored lowering the minimum output levels of the plant, and has found technical and operational challenges that prevent it from being decreased from its current limit.

l. Current plant committed ramp rate is 5.0 Megawatts per minute (MW/min). Based on the last Southwest Reserve Sharing Group (SRSG) test the Unit 4 achieved a ramp rate of 5.3 MW/min. while Unit 5 achieved 5.1 MW/min. However, over the longer period of time the average ramp rate are 4.5 MW/min for Unit 4 and 4.1 MW/min for Unit 5.

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SC 1.12: Please confirm that APS did not evaluate any alternatives that included the retirement of any Four Corners plant units prior to 2031 as part of its 2017 IRP.

a. If not confirmed, explain why not.

b. Is APS committing to conduct any economic evaluation of alternative Four Corners retirement dates as part of its 2020 IRP?

   i. If so, explain APS's planned process for evaluating economic retirement dates for the Four Corners units.

   ii. If not, explain why not.

Response: APS will provide a response to this request subject to and without waiving the objection(s) below.

APS objects to this request to the extent that it seeks information regarding the prudency of the Four Corners Power Plant and the need to install the Selective Catalytic Reduction (SCR) equipment. The discovery sought is neither relevant nor reasonably calculated to lead to admissible evidence for any party's claim or defense, and is not proportional to the needs of the case. The prudency of the continued operation of the Plant was litigated and conclusively decided in prior Commission decisions in which the Sierra Club participated. This matter is not the appropriate mechanism for seeking to reopen and modify final Commission decisions under Arizona law.

Supplemental Response:

a. Confirmed. APS did not evaluate alternatives that retired Four Corners prior to 2031 in its 2017 IRP for several reasons. Four Corners is jointly owned by APS and four other entities and together, owners have a coal contract that runs through 2031. It is not an option for APS to retire the plant without agreement of the other owners. Furthermore, community impacts of retiring the plant are significant and must be carefully considered even before such evaluations could be made. Please note that Four Corners Units 1, 2, and 3 were retired in 2012.

b. No.

   i. N/A.

   ii. Please see response to SC 1.12a

Witness: Brad Albert

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SC 1.16: For each of the Company's coal and natural gas units, please provide, based on the most recent forecast, for each of the years 2019 through 2035, please specify the percentage of ownership being reported and identify the projected:

a. Installed capacity.

b. Capacity factor.

c. Summer capacity rating.

d. Forced outage rate.

e. Planned outage rate.

f. Equivalent Availability Factor (EAF).

g. Heat rate.

h. Generation.

i. Fixed O&M costs.

j. Non-fuel variable O&M costs.

k. Fuel costs.

l. Fuel usage (MMBtu) by type.

m. Environmental capital costs.

n. Non-environmental capital costs.

o. Energy revenues (i.e., avoided energy purchase costs).

p. Ancillary services revenues.

q. Any other revenues.

r. Depreciation cost.

s. Undepreciated net book value.

t. Property taxes.

u. Property insurance.

Witness: Brad Albert

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Response: Subject to and without waiving the objection(s) below, APS will provide responsive information for its most recent forecast and subject to its receipt of an executed Protective Agreement. Please note that some of this information may only be provided upon execution of a Protective Agreement because the information is either Confidential or Highly Confidential.

APS objects that this request is overly broad, cumulative, and unduly burdensome, to the extent it seeks all forecasts related to all subparts of the request for a period of more than 15 years.

Supplemental Response: Please see ExcelAPS1900884 and ExcelAPS19RC00885 for the requested information. This information is Highly Confidential and is being provided pursuant to an executed Protective Agreement in this docket. Also the information provided below reflects APS ownership share. Some of the information is available and provided on a unit level, while some is only available and provided at a plant level.

a. Please see ExcelAPS19RC00885, "APS Unit Capacity" tab, column B.

b. Please see ExcelAPS19RC00885, "APS Unit" tab.

c. Please see ExcelAPS19RC00885, "APS Unit Capacity" tab, column C.

d. Please see ExcelAPS19RC00885, "APS Unit EFOR" tab, column B for EFOR, and column C for FOR.

e. Please see ExcelAPS19RC00885, "APS Unit Planned Maintenance" tab.

f. Equivalent Availability Factor can be calculated from information provided in sub-parts d and e.

g. Please see APS's response to part b above.

h. Please see APS's response to part b above.

i. Please see ExcelAPS19RC00884 for the information report at plant level.

Witness: Brad Albert

j. Please see APS's response to part b above.

k. Please see APS's response to part b above.

l. Please see APS's response to part b above.

m. APS is still working to compile this information and will supplement this response as soon as the information is available.

n. Please see APS's response to part m above.

o. APS does not forecast this information.

p. APS does not forecast this information.

q. APS does not forecast this information.

r. Please see APS's response to part i above.

s. Please see APS's response to part i above (column entitled "BOY OCLD").

t. Please see APS's response to part i above.

u. Property insurance is carried at the PNW level, and is not forecasted at sub-levels such as power plants.

Witness: Brad Albert

SC 1.16: For each of the Company's coal and natural gas units, please provide, based on the most recent forecast, for each of the years 2019 through 2035, please specify the percentage of ownership being reported and identify the projected:

a. Installed capacity.

b. Capacity factor.

c. Summer capacity rating.

d. Forced outage rate.

e. Planned outage rate.

f. Equivalent Availability Factor (EAF).

g. Heat rate.

h. Generation.

i. Fixed O&M costs.

j. Non-fuel variable O&M costs.

k. Fuel costs.

l. Fuel usage (MMBtu) by type.

m. Environmental capital costs.

n. Non-environmental capital costs.

o. Energy revenues (i.e., avoided energy purchase costs).

p. Ancillary services revenues.

q. Any other revenues.

r. Depreciation cost.

s. Undepreciated net book value.

t. Property taxes.

u. Property insurance.

Response: Subject to and without waiving the objection(s) below, APS will provide responsive information for its most recent forecast and subject to its receipt of an executed Protective Agreement. Please note that some of this information may only be provided upon execution of a Protective Agreement because the information is either Confidential or Highly Confidential.

APS objects that this request is overly broad, cumulative, and unduly burdensome, to the extent it seeks all forecasts related to all subparts of the request for a period of more than 15 years.

Supplemental Response: Please see ExcelAPS1900884 and ExcelAPS19RC00885 for the requested information. This information is Highly Confidential and is being provided pursuant to an executed Protective Agreement in this docket. Also the information provided below reflects APS ownership share. Some of the information is available and provided on a unit level, while some is only available and provided at a plant level.

a. Please see ExcelAPS19RC00885, "APS Unit Capacity" tab, column B.

b. Please see ExcelAPS19RC00885, "APS Unit" tab.

c. Please see ExcelAPS19RC00885, "APS Unit Capacity" tab, column C.

d. Please see ExcelAPS19RC00885, "APS Unit EFOR" tab, column B for EFOR, and column C for FOR.

e. Please see ExcelAPS19RC00885, "APS Unit Planned Maintenance" tab.

f. Equivalent Availability Factor can be calculated from information provided in sub-parts d and e.

g. Please see APS's response to part b above.

h. Please see APS's response to part b above.

i. Please see ExcelAPS19RC00884 for the information report at plant level.

j. Please see APS's response to part b above.

k. Please see APS's response to part b above.

l. Please see APS's response to part b above.

m. APS is still working to compile this information and will supplement this response as soon as the information is available.

n. Please see APS's response to part m above.

o. APS does not forecast this information.

p. APS does not forecast this information.

q. APS does not forecast this information.

r. Please see APS's response to part i above.

s. Please see APS's response to part i above (column entitled "BOY OCLD").

t. Please see APS's response to part i above.

u. Property insurance is carried at the PNW level, and is not forecasted at sub-levels such as power plants.

Second Supplemental Response: For parts m and n, please see the updated attachment ExcelAPS19RC00884A, which contains in Column G of each tab a capital forecast from approximately June 2018, including both environmental and non-environmental capital. This information is Highly Confidential and being provided pursuant to an executed Protective Agreement.

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SC 1.17:

For each of the Company's coal units, please identify the amount of money that APS has included in the Company's Test Year spending as proposed in this case, by the following types:

a. Capital.

b. Fuel.

c. Non-fuel Operations & Maintenance.

d. Other.

Response: The summary below reflects the total company amounts included in the adjusted Test Year by Plant and by type. Please also refer to APS's response to Sierra Club 1.18, which states APS is not proposing a change to the base fuel rate.

<u>Four Corners</u>

a. $833,795,812 – Net Book Value @ 6/30/2019
b. $187,509,568 – fuel expense
c. $101,885,495 – non-fuel O&M expense
d. $1,078,301 – other income

<u>Cholla</u>

a. $301,032,062 – Net Book Value @ 6/30/2019
b. $44,474,569 – fuel expense
c. $37,473,111 – non-fuel O&M expense
d. $60,267 – other income

<u>Navajo</u>

a. $0 - Net Book Value @ 6/30/2019, item is a Regulatory Asset with book value of $73,226,933 @ 6/30/2019
b. $36,636,648 – fuel expense
c. None
d. None

Witness: Elizabeth Blankenship

SC 1.21: Please provide each forecast produced by or for the Company for the years 2015 through present (latest available) and specify the percentage of ownership being reported (where applicable):

a. Wholesale energy market prices.

b. Coal prices.

c. Natural gas prices.

d. Generation of each Four Corners unit.

e. Forced outage rate at each Four Corners unit.

f. Planned outage rate at each Four Corners unit.

g. Fixed O&M costs at each Four Corners unit.

h. Non-fuel variable O&M costs at each Four Corners unit.

i. Fuel costs at each Four Corners unit.

j. Fuel usage (MMBtu) by type at each Four Corners unit.

k. Environmental capital costs at each Four Corners unit.

l. Non-environmental capital costs at each Four Corners unit.

m. For (a)-(l), provide the date each forecast was produced.

Response: APS objects to this request to the extent that it seeks information regarding the prudency of the Four Corners Power Plant and the need to install the Selective Catalytic Reduction (SCR) equipment. The discovery sought is neither relevant nor reasonably calculated to lead to admissible evidence for any party's claim or defense, and is not proportional to the needs of the case. The prudency of the continued operation of the Plant was litigated and conclusively decided in prior Commission decisions in which the Sierra Club participated. This matter is not the appropriate mechanism for seeking to reopen and modify final Commission decisions under Arizona law.

In addition, this request is overly broad, unduly burdensome, and cumulative, to the extent it seeks all forecasts from 2015 to the

Response to SC 1.21 (continued):	present, APS also objects information is either Confidential or Highly Confidential.
Supplemental Response:	Subject to and without waiving its prior objections, and pursuant to an agreement with Sierra Club in an effort to resolve discovery disputes, APS is providing the requested information from three forecasts – the APS 2012, 2014 and 2017 IRPs, each of which have also been provided in APS's response to SC 1.23. Please see the attached document APS19RC01063 for reference to where the information is located in the IRPs themselves, and ExcelAPS19RC01064 for supplemental information of the same vintage that was not contained in the IRPs. Information provided in spreadsheet ExcelAPS19RC001064 is Confidential and is being provided pursuant to an executed Protective Agreement in this docket.

a. Please see the attached spreadsheet ExcelAPS19RC01064.

b. Please see the cross-reference document APS19RC01063.

c. Please see the cross-reference document APS19RC01063.

d. Please see the cross-reference document APS19RC01063.

e. Please see the attached spreadsheet ExcelAPS19RC01064.

f. Please see the attached spreadsheet ExcelAPS19RC01064.

g. Please see the cross-reference document APS19RC01063.

h. Please see the cross-reference document APS19RC01063.

i. Please see the cross-reference document APS19RC01063.

j. Please see the cross-reference document APS19RC01063.

k. Please see the attached spreadsheet ExcelAPS19RC01064.

l. Please see the attached spreadsheet ExcelAPS19RC01064.

m. 2012 IRP information was prepared in September 2011; 2014 IRP information was prepared in September 2013; and 2017 IRP information was prepared in September 2016.

Witness: Brad Albert

SIERRA CLUB'S FIRST SET OF DATA REQUESTS TO ARIZONA PUBLIC SERVICE COMPANY REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
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SC 1.22: Please provide each forecast reviewed by the Company developed in 2015 through present (or the latest available) regarding:

a. Wholesale energy market prices.

b. Coal prices.

c. Natural gas prices.

d. For (a)-(c), provide dates that these forecasts were reviewed—preferably the day, if not the month.

Response: Subject to and without waiving the objection(s) below, APS will provide responsive information for its most recent forecast and subject to its receipt of an executed Protective Agreement.

APS objects that this request it is overly broad, cumulative, and unduly burdensome, and seeks APS information that is either Confidential or Highly Confidential, as well as Confidential or Highly Confidential information owned by third parties and which APS is prohibited from disclosing.

APS also objects that this request seeks information that is vague, irrelevant, overly broad and unduly burdensome, to the extent the requests seeks specific details regarding each forecast reviewed by date.

Supplemental Response: Please see ExcelAPS19RC00773 for fuel and wholesale power prices used in APS planning models, one for each year beginning in 2015. Many forecasts from third party sources are reviewed and used in the development of these prices as described below. APS has contracts with the third party sources that prohibit the Company from disclosing this information.

a. The Company does not just rely on one forecast for wholesale energy market prices. Wholesale energy market prices are analyzed on a daily basis, with information coming from four external brokers.

b. Coal pricing is based upon a variety of indexes spelled out in the APS's coal supply agreements. Historical and forward index trends are internally reviewed twice annually, generally in the March and September time frames.

c. Natural gas prices are received daily and are based upon ICE cleared prices for both basins from which APS procures gas.

d. Please see APS's responses to a through c above.

Witness: Brad Albert

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SC 1.23: Please provide the last three Integrated Resource Plans (IRPs) developed by the Company, in unredacted form.

Response: Please see the attachments below. Confidential and Highly Confidential versions of the Company's IRPs as shown below are being provided pursuant to an executed Protective Agreement in this docket.

Non-Confidential IRP Versions:

APS 2012 IRP	APS19RC00713
APS 2012 IRP Revisions	APS19RC00761
APS 2014 IRP	APS19RC00714
APS 2017 IRP	APS19RC00715

Confidential and Highly Confidential IRP Versions:

APS 2012 IRP Confidential Excerpts	APS19RC00762
APS 2012 IRP Confidential Revisions	APS19RC00716
APS 2014 IRP Confidential Excerpts	APS19RC00717
APS 2017 IRP Confidential Version	APS19RC00715

Witness: Brad Albert

SC 1.26: Refer to the Direct Testimony of Barbara D. Lockwood, page 5, line 21 through page 6, line 5.

a. Identify and produce any analyses, studies, or other documents supporting the prudency of the Four Corners SCR Project.

b. Did the Company conduct an economic or net present value analysis of the SCR investment at Four Corners, relative to other supply- and demand-side alternatives, prior to deciding to installing the SCR?

   i. If so:

      1. Identify the date and describe the results of each such analysis.

      2. Provide all economic analyses conducted prior to the SCR installation, including supporting workpapers and any modeling input and output files, in executable format (preferably Excel) with all calculations and formulas intact.

   ii. If not, explain why not.

c. Has the Company conducted any forward-looking economic or net present value analysis of either or both of Four Corners Units 4 and 5 relative to other supply- and demand-side resource options since construction of the SCR began?

   i. If so:

      1. Identify the date and describe the results of each such analysis.

      2. Provide all economic analyses conducted since the start of the SCR project, including supporting workpapers and any modeling input and output files in executable format (preferably Excel) with all calculations and formulas intact.

   ii. If not, explain why not.

Witness: Barbara Lockwood

SC 1.26 (continued):

d. Has the Commission previously approved of APS's plan to construct the SCR project?

i. If so, identify the Commission order approving that plan.

Response: Subject to and without waiving the objection(s) below, APS will provide some responsive information for subparts (a) and (b). Please note that some of this information may only be provided upon execution of a Protective Agreement because the information is either Confidential or Highly Confidential. APS will provide this responsive information upon its receipt of an executed Protective Agreement.

APS objects to this request to the extent that it seeks information regarding the prudency of the Four Corners Power Plant and the need to install the Selective Catalytic Reduction (SCR) equipment. The discovery sought is neither relevant nor reasonably calculated to lead to admissible evidence for any party's claim or defense, and is not proportional to the needs of the case. The prudency of the continued operation of the Plant was litigated and conclusively decided in prior Commission decisions in which the Sierra Club participated. This matter is not the appropriate mechanism for seeking to reopen and modify final Commission decisions under Arizona law.

Supplemental Response:

a. The SCR projects were mandated by the EPA in 2012 as a condition to continue operations of the plant past July of 2018. In anticipation of that federal mandate, the SCRs were included in the analyses filed with the ACC in 2010 when APS sought approval to acquire SCE's share of Four Corners Units 4 and 5 (Docket No. E-01345A-10-0474). And after the EPA's mandate, APS included consideration of the SCRs in its 2013 filing when it sought a Commission determination that the Four Corners Acquisition was prudent (Docket No. E-01345A-11-0224). Importantly, the Commission found the acquisition to be prudent while acknowledging that the SCR installation was needed to keep Four Corners running after 2018. This finding necessarily means that prudency of APS's installation of SCRs has already been decided by the Commission. Please also see the Administrative Law Judge's Recommended Opinion and Order (issued November 27, 2018) in Docket No. E-01345A-16-0036 et. al., which recommends the testimony and evidence presented in that case supports a finding that

Supplemental Response to SC 1.26 (continued):

the SCR project was completed in a reasonable, cost-efficient, and prudent manner.

b. Yes. In 2008, and 2009, as part of the Best Available Retrofit Technology (BART) analysis required by the Environmental Protection Agency (EPA) under the Clean Air Act, APS evaluated more than a dozen alternatives for reducing emissions from the Four Corners Power Plant. Please see the attached document APS19RC00799 – Black and Veatch Final NOx Compliance Report for Four Corners Steam Electric Station Units 1 through 5, released in 2010. In addition, attached as APS19RC00800 is a presentation made in 2009 to the Commission regarding APS's SCR analysis.

c. Notwithstanding the above objection, APS responds that other than the overall analyses conducted in conjunction with the Commission's Integrated Resource Planning process, the Company has not conducted any forward-looking economic analysis of either or both of Four Corners Units 4 and 5 since the SCR project began in early 2014. The decision to continue operation of Four Corners was made in conjunction with the execution of agreements and commitments with other plant owners, the coal provider, and the Navajo Nation.

d. Yes. Please see the Company's response to part a.

SC 1.27: Refer to the Direct Testimony of Barbara D. Lockwood, page 8, lines 5-8.

a. Explain the basis for your claim that the Four Corners SCR investment was "necessary to provide reliable, cleaner, and sustainable power to our customers."

b. Is the Company's determination that the Four Corners SCR investment was "necessary" based on an economic assessment?

   i. If so, identify that assessment and provide all supporting calculations, data, documents, modeling input and output files, and work papers associated with that assessment.

c. Identify the date when APS decided to proceed with the SCR project.

d. Identify and produce any documentation of APS's decision to proceed with the SCR project.

e. Identify the date when the Engineering, Procurement, and Construction ("EPC") contract for the SCR project was entered into by APS.

f. Produce the EPC contract for the SCR project.

g. Identify the earliest and latest date on which APS entered into contracts to purchase the SCR equipment for Four Corners Unit 5.

h. Identify the earliest and latest date on which APS entered into contracts to purchase the SCR equipment for Four Corners Unit 4.

i. Identify the date when construction on the SCR project was commenced.

j. Please provide the amount of capital spending, by month, on the SCR project.

k. Please provide the dates that each unit was unavailable due to the SCR installation.

l. Please provide the Company's forecasts of operations and maintenance costs for the SCR produced in 2015 through present (latest available).

Witness: Barbara Lockwood

Response to SC 1.27:

a. The SCR projects were mandated by the EPA in 2012 as a condition to continue operations of the plant past July of 2018. In anticipation of that federal mandate, the SCRs were included in the analyses filed with the Commission in 2010 when APS sought approval to acquire SCE's share of Four Corners Unit 4 and 5 (Docket No. E-01345A-10-0474). After the EPA's mandate, APS included consideration of the SCRs in its 2013 filing when it sought a determination that the Four Corners acquisition was prudent (Docket No. E-01345A-11-0224). Importantly, the Commission found the acquisition to be prudent while acknowledging that the SCR installation was needed to keep Four Corners running after 2018. This finding necessarily means that prudency of APS's installation of SCRs has already been decided by the Commission. Please also see the Administrative Law Judge's Recommended Opinion and Order (issued November 27, 2018) in Docket No. E-01345A-16-0036 et. al., which recommends the testimony and evidence presented in that case supports a finding that the SCR project was completed in a reasonable, cost-efficient, and prudent manner.

   Installation of the SCRs, in conjunction with the acquisition of SCE's share of Four Corners, allowed APS to maintain generation consistent with the load growth in the Company's service territory. The combination of the Four Corners acquisition and the SCR installation ensures the continued provision of reliable and reasonably priced electricity for the Company's customers. Please also see Decision No. 74876.

b. Please see the Company's response to SC 1.27.a.

c. The SCR project was an integral part of the Company's acquisition of SCE's portion of Four Corners Units 4 and 5, which closed on December 31, 2013.

d. Please see the following attached documents:

Purchase and Sale Agreement (between SCE and APS for a portion of Four Corners Units 4 and 5)	APS19RC00767
Consent Decree (USA/EPA v. APS et.al.)	APS19RC00768

Witness: Barbara Lockwood

Response to SC 1.27 (continued):

Source Specific Federal Implementation Plan (FIP) for Four Corners (as published in the Federal Register)	APS19RC00769

e. The Four Corners SCR Engineering, Procurement, and Construction (EPC) contract was executed on August 27, 2015.

f. The EPC contract is attached as ASP19RC00772. This contract is Highly Confidential and is being provided pursuant to an executed Protective Agreement in this docket.

g. Pursuant to the EPC contract, APS did not contract directly for any SCR equipment.

h. Please see the Company's response to SC 1.27.g.

i. Construction on the Four Corners SCR project began on September 14, 2015.

j. Please see the attached spreadsheet ExcelAPS19RC00770.

k. Four Corners Unit 5 was unavailable due to SCR construction from September 16, 2017 through December 17, 2017. Four Corners Unit 4 was unavailable due to SCR construction from January 20, 2018 through April 24, 2018.

l. Please see the attached document APS19RC00771 for the requested O&M forecasts.

Witness: Barbara Lockwood

SIERRA CLUB'S SECOND SET OF DATA REQUESTS TO ARIZONA PUBLIC SERVICE COMPANY REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
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APRIL 8, 2020

SC 2.1: Refer to "SC 1.23_APS19RC00762_2012 IRP Excerpts_CONF", "SC 1.23_APS19RC00717_APS 2014 IRP - CONF PORTION" and "SC 1.23_APS19RC00718_APS 2017 IRP - CONF".

a. For every portfolio and sensitivity modeled in the 2014 and 2017 IRPs, please provide the annual revenue requirements for all years modeled and preferably in Excel format.

b. For every portfolio and sensitivity modeled in each (2012, 2014, and 2017) IRP, please provide the following on an annual basis for Four Corners units 4 and 5 (separately for each unit, where available) for all years modeled and preferably in Excel format:

i. Capacity factor (%)
ii. Capacity (MW)
iii. Generation (MWh)
iv. Fixed O&M ($/MW)
v. Variable O&M ($/MWh)
vi. Capital expenditures ($)
vii. Coal burn (MMBtu)
viii. Fuel cost ($), including a breakdown of fixed and spot purchases (if applicable)
ix. Lease costs ($)
x. Revenue requirement ($), including supporting calculations

Initial Response: APS objects to this request as unduly burdensome and not proportional to the needs of this case. In addition, the request is overly broad and duplicative. APS has already provided extensive information to the Sierra Club, including information regarding its prior IRPs. APS also objects to the extent this request seeks to have APS conduct new model runs or new analysis. APS has no obligation to create new documents or conduct analysis for Sierra Club. Subject to and without waiving its objections, APS will provide responsive information.

Supplemental Response: a. Please see the attachments listed below for the annual revenue requirements of every portfolio modeled in the 2017 IRP. The information in the spreadsheets provided in response to this subpart is Confidential and is being provided pursuant to an executed Protective Agreement in this docket. Please note that all of the requested information for the 2014 IRP is available within that IRP, as provided in the Company's response to SC 1.23.

Witness: Brad Albert

SIERRA CLUB'S SECOND SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO
DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-19-0236
APRIL 8, 2020

Supplemental Response to SC 2.1 (continued):

CarbonReduction TOTAL REV REQ	ExcelAPS19RC01237
EnergyStorageSystems TOTAL REV REQ	ExcelAPS19RC01238
ExpandedDSM TOTAL REV REQ w TRC	ExcelAPS19RC01239
ExpandedRenewable TOTAL REV REQ	ExcelAPS19RC01240
FlexibleResourceSELECTED TOTAL REV REQ	ExcelAPS19RC01241
NuclearSMR TOTAL REV REQ	ExcelAPS19RC01242
ResourceMandates TOTAL REV REQ w TRC	ExcelAPS19RC01243

b. Information for each of the subparts i. through x. is provided for Four Corners Units 4 and 5 combined, for each portfolio modeled in the 2012, 2014, and 2017 IRPs as indicated in the table below. The information in the spreadsheets provided in response to this subpart is Confidential and is being provided pursuant to an executed Protective Agreement in this docket.

	2012 IRP	2014 IRP	2017 IRP
i. Capacity factor (%)	ExcelAPS19RC01244	ExcelAPS19RC01247	ExcelASP19RC01250
ii. Capacity (MW)	ExcelAPS19RC01244	ExcelAPS19RC01247	ExcelAPS19RC01250
iii. Generation (MWh)	ExcelAPS19RC01244	ExcelAPS19RC01247	ExcelAPS19RC01250
iv. Fixed O&M ($/MW)[1]	ExcelAPS19RC01244	ExcelAPS19RC01247	ExcelAPS19RC01250
v. Variable O&M ($/MWh)[2]	ExcelAPS19RC01244	ExcelAPS19RC01247	ExcelAPS19RC01250
vi. Capital expenditures ($)	ExcelAPS19RC01245	ExcelAPS19RC01248	ExcelAPS19RC01251
vii. Coal burn (MMBtu)[3]	ExcelAPS19RC01246	ExcelAPS19RC01249	ExcelAPS19RC01252
viii. Fuel cost ($)[4]	ExcelAPS19RC01244	ExcelAPS19RC01247	ExcelAPS19RC01250
ix. Lease costs ($)[5]	ExcelAPS19RC01244	ExcelAPS19RC01247	ExcelAPS19RC01250
x. Revenue requirement ($)	ExcelAPS19RC01244	ExcelAPS19RC01247	ExcelAPS19RC01250

[1] Provided in millions of dollars. Cost in $/MW can be calculated using $millions and information provided in ii. Capacity (MW). Values in $/MW are also provided in the IRPs, Attachment D.1(a)(6).
[2] Provided in millions of dollars. Cost in $/MWh can be calculated using $millions and information provided in iii. Generation (MWh). Values in $/MWh are also provided in the IRPs, Attachment D.1(a)(1).
[3] Provided in tons. Coal Burn (MMBtu) can be calculated from tons and heating value (MMBtu/ton) which is also provided.
[4] See also IRP_CoalBurn_LDs attachments in each IRP year for liquidated damages which were not included in this attachment.
[5] Plant Lease costs are included in and inseparable from "Fixed Fuel and O&M".

Witness: Brad Albert

SIERRA CLUB'S SECOND SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO
DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E 01345A 19 0236
APRIL 8, 2020

SC 2.3: Refer to "SC 1.4 APS19RC00886 HIGHLY CONF Coal Supply Agreement."

a. Has this coal contract (including any amendments) been approved by the Commission? Please explain.

b. Through what mechanisms does APS anticipate recovering from ratepayers APS's share of the cost of coal supplied under this contract? If through APS's "power supply adjustor," please provide a breakdown of the costs APS has included in the adjustor for 2019 and 2020 specific to recovery of APS's share of costs under this coal contract.

c. At page p.43, Section 17.1, the contract states that [redacted]

i. [redacted]

ii. [redacted]

d. Refer to Section 4.4c.

i. [redacted]

SIERRA CLUB'S SECOND SET OF DATA REQUESTS TO ARIZONA PUBLIC SERVICE COMPANY REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-19-0236
APRIL 8, 2020

SC 2.3 (continued): [redacted]

ii. [redacted]

e. Refer to Section 6.1.

i. Please provide what APS has paid so far in terms [redacted]

ii. Please provide what APS has paid so far that is in addition [redacted]

iii. Please provide APS's forecast for the annual costs it will pay [redacted]

iv. Please provide APS's forecast for the annual costs it will pay on this contract, [redacted]

f. Refer to SC 1.4_APS19RC00886_HIGHLY CONF_Coal Supply Agreement, Section 20.

i. Please provide any estimates that APS has conducted or reviewed on the costs [redacted]

ii. Please provide any estimates that APS has conducted or reviewed on [redacted]

iii. Please explain if APS would still have [redacted] in the event of a shut down before the end of the contract term.

Initial Response: Subject to and without waiving the objections below, APS will produce responsive information. APS objects to this data request as unduly burdensome and not proportional to the needs of this case. In addition, the request seeks information that is immaterial to the issues presented in this proceeding. As to request 2.3(c), APS also objects because it seeks a legal interpretation and conclusion and calls for

Response to SC 2.3 (continued): Agreement speaks for itself. Finally, APS objects to the extent that this request seeks information that is protected by the attorney client privilege or work product doctrine.

Supplemental Response:

a. No. Commission approval is not a required for APS, or any other electric utility, to sign fuel contracts. APS is subject to periodic fuel audits where the Commission reviews APS's fuel contracts.

b. APS collects fuel costs, including coal, through base fuel expense, which is set in a rate case, and its Power Supply Adjustor, which operates according to its Plan of Administration. Please see table below. Please also note that 2020 data will be available subsequent to public release of information through the Company's 10-Q filings.

Cost Category	**2019 CSA Costs ($000)**
FC 4 APS Coal Fuel	$ 116,195
FC 5 APS Coal Fuel	$ 92,171
APS share of Four Corners common costs	$ 547
Total	$208,913

c. Please see the Company's Initial Response to SC 2.3.

d. i. Please see attachment APS19RC01236, which is Confidential and is being provided pursuant to an executed Protective Agreement.

ii. Please see attachment APS19RC01236, which is Confidential and is being provided pursuant to an executed Protective Agreement.

e. i. Please see attachment APS19RC01236, which is Confidential and is being provided pursuant to an executed Protective Agreement.

ii. Please see attachment APS19RC01236, which is Confidential and is being provided pursuant to an executed Protective Agreement.

iii. Please see attachment APS19RC01236, which is Confidential and is being provided pursuant to an executed Protective Agreement

Witness: Brad Albert

Response to SC 2.3 (continued):

iv. Please see attachment APS19RC01236, which is Confidential and is being provided pursuant to an executed Protective Agreement

f.

i. The study estimating early closure effects on Final Reclamation Costs is attached as APS19RC01223.

ii. The most recent estimate of the "Seller's Stranded Costs" is attached as ExcelAPS19RC01224.

iii. No. Under this hypothetical, APS might consider exercising a contractual provision that allows for a 24-month notice to terminate if the plant is closed prior to 2031.

Second Supplemental Response:

b. While preparing this second supplemental response, APS discovered the table originally provided for part b included first quarter 2020 information. As a result, the table below was corrected to show 2019 information as previously noted.

Cost Category	**2019 CSA Costs ($000)**
FC 4 APS Coal Fuel	$ 92,966
FC 5 APS Coal Fuel	$ 77,520
APS share of Four Corners common costs	$ 524
Total	$171,010

Please see below for year-to-date June 30,2020 information.

Cost Category	**Jan-June 2020 CSA Costs ($000)**
FC 4 APS Coal Fuel	$ 36,598
FC 5 APS Coal Fuel	$ 27,880
APS share of Four Corners common costs	$ 236
Total	$ 64,714

Third Supplemental Response:

f. i. Upon further review, APS has determined that the previously provided document APS19RC01226 is Confidential. Please destroy all prior copies and replace with the attached document APS19RC01226A, which contains the exact same information but is correctly labeled as Confidential. Please note because this document is Confidential, it is being provided pursuant to an executed Protective Agreement in this case.

Witness: Brad Albert

NTEC
Schedule of Sellers stranded costs

Fiscal Year Ending 12/31	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Sustaining Capex																
CapEx (15 Year Book Life)		3,854	1,171	3,901	-	-	-	-	-	-	-	-	-	-	-	-
CapEx (10 Year Book Life)		24,410	7,418	24,707	10,500	7,500	7,500	7,500	7,500	11,250	11,250	-	-	-	-	-
CapEx (5 Year Book Life)		3,854	1,171	3,901	3,500	2,500	2,500	2,500	2,500	3,750	3,750	5,000	3,000	3,000	3,000	-
Total CapEx Additions		32,119	9,761	32,509	14,000	10,000	10,000	10,000	10,000	15,000	15,000	5,000	3,000	3,000	3,000	-
Depreciation																
Book Depreciation (For Assets Acquired after 12/31/2016)		2,655	3,056	8,032	11,245	12,903	13,224	13,224	13,210	12,740	13,157	13,007	12,131	10,056	8,580	6,665
Book Depreciation (For Assets Acquired Before 12/31/2016)		9,564	6,617	3,617	2,616	2,372	1,586	1,342	1,214	1,133	1,063	846	829	758	502	110
Other																
Total Depreciation		12,219	9,673	11,649	13,861	15,274	14,810	14,566	14,425	13,873	14,220	13,853	12,959	10,824	9,082	6,776
PPE balance:																
Beginning balance		35,760	55,660	55,749	76,609	76,748	71,474	66,665	62,099	57,674	58,801	59,582	50,729	40,769	32,946	26,864
Additions		32,119	9,761	32,509	14,000	10,000	10,000	10,000	10,000	15,000	15,000	5,000	3,000	3,000	3,000	-
Depreciation		(12,219)	(9,672)	(11,649)	(13,861)	(15,274)	(14,810)	(14,566)	(14,425)	(13,873)	(14,220)	(13,853)	(12,959)	(10,824)	(9,082)	(6,776)
Ending balance	35,760	55,660	55,749	76,609	76,748	71,474	66,665	62,099	57,674	58,801	59,582	50,729	40,769	32,946	26,864	20,088

SIERRA CLUB'S THIRD SET OF DATA REQUESTS TO ARIZONA PUBLIC SERVICE COMPANY REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-19-0236
JUNE 9, 2020

Sierra Club 3.1: Refer to SC 2.3_APS19RC01236_FC Coal Cost Information and Forecasts_CONF and SC 2.3_ExcelAPS19RC01224_Sellers Stranded Costs 2019.

a. Please confirm that the [redacted] in every year shown, are unavoidable if APS were to terminate the contract prior to 2031.

   i. If any of these costs are avoidable if APS were to terminate the contract prior to 2031, please specify which costs would be avoidable, relative to the termination date—for each year after 2020 that APS could terminate the contract.

b. Do any of the costs shown in SC 2.3_ExcelAPS19RC01224_Sellers Stranded Costs 2019 overlap with those shown in SC 2.3_APS19RC01236_FC Coal Cost Information and Forecasts_CONF?

c. If so, please specify which costs are included in both.

d. Please provide what amount of the stranded costs shown in SC 2.3_ExcelAPS19RC01224_Sellers Stranded Costs 2019 that APS would need to pay if it were to terminate the contract—for each year after 2020 that APS could terminate the contract.

Response: a. Not all costs listed are unavoidable if the contract were to terminate prior to 2031.

   i. APS Fuel Cost, LD Price and Performance Bond costs are avoidable if APS exercised the contractual provision that allows for a 24-month notice to terminate if the plant is closed prior to 2031.

b. There are no cost overlaps between the two cost estimations.

c. N/A

d. Please see the table below.

Response to SC 3.1 (continued):

Date	APS Share of Expected Termination Expense
7/1/2020	$48,351,486
7/1/2021	$45,028,805
7/1/2022	$41,998,645
7/1/2023	$39,122,324
7/1/2024	$36,334,722
7/1/2025	$37,044,832
7/1/2026	$37,536,409
7/1/2027	$31,959,153
7/1/2028	$25,684,685
7/1/2029	$20,755,739
7/1/2030	$16,924,188
7/6/2031	$12,787,096

SIERRA CLUB'S SIXTH SET OF DATA REQUESTS TO ARIZONA PUBLIC SERVICE COMPANY REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN DOCKET NO. E-01345A-19-0236 JULY 23, 2020

SC 6.1: Refer to SC 1.16_ExcelAPS19RC00885 and SC 1.16_ExcelAPS19RC00884A.

a. Please provide the dates that these forecasts were produced by or for the Company.

b. As Sierra Club requested informally on July 15, please confirm that APS does not have any more recent forecasts that would be responsive to SC 1.16.

i. If not confirmed, please provide a supplemental response to SC 1.16 based on the most recent forecast produced by or for the Company.

Response:

a. Information in these forecasts was produced between the third quarter of 2016 and the third quarter of 2019.

b. The forecasts were updated in the Company's 2020 Integrated Resource Plan which was filed June 26, 2020 in Docket No. E00000V-19-0034.

i. Please see APS's third supplemental response to SC 1.16.

Witness: Brad Albert

SC 6.4: Refer to Citizen Groups 2.13_APS19RC01444_2020 Confidential IRP_CONF.

a. Does the fixed O&M shown for Four Corners Units 4 and 5 include "fixed fuel" costs?

   i. If not, please provide annual fixed fuel costs.

b. Please provide the pre-tax rate of return assumed in the 2020 IRP.

c. Please provide all projected costs at Four Corners Units 4 and 5 for each portfolio and scenario in the 2020 IRP, including supporting calculations.

d. Please provide projected annual revenue requirements for Four Corners Units 4 and 5 for each portfolio and scenario in the 2020 IRP, including supporting calculations.

e. Please provide projected levelized costs of Four Corners Units 4 and 5 for each portfolio and scenario in the 2020 IRP, including supporting calculations.

Response:

a. Yes.

b. The pre-tax rate of return assumed in the 2020 IRP is 10.07%.

c. Please see Attachments APS19RC01800 through APS19RC01820 for Four Corners 4 and 5 annual costs and revenue requirements for each portfolio and scenario in the 2020 IRP. Note that annual capital additions are provided in response to SC 6.1. Liquidated damages associated with the coal contract are not included in the revenue requirements and are provided in Attachment APS19RC01821.

   Please note the information in these attachments is Confidential and is being provided pursuant to an executed Protective Agreement in this docket.

d. Please see the Company's response to part c.

e. Please see the Company's response to part c.

Witness: Brad Albert

SIERRA CLUB'S SEVENTH SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO
DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-19-0236
AUGUST 26, 2020

Sierra Club 7.1: Refer to SC 6.3_APS19RC01796_BDL-4DR FC Projects and SC 6.3_APS19RC01797_BDL-5DR FC Projects.

a. For those projects already in process or completed, could APS have avoided any of the associated spending if—prior to starting each project—APS had decided to retire the Four Corners units at the end of 2023?

i. If so, please identify the costs that could have been avoided for each project. Please provide supporting documentation and analyses used in making this determination.

ii. For all unavoidable spending, please explain why it would be necessary if the units were retired at the end of 2023. Please note, for the purposes of this question, commencement of construction would not make a project unavoidable because the question assumes a 2023 retirement was selected before the project was started.

Response: APS objects to this request as it seeks documents and speculative information that does not exist. The question asks a hypothetical, what if, question about the Four Corners Power Plant and asks APS to speculate about actions it could have taken if the plant were to close in 2023.

In addition, APS objects that this request is unduly burdensome to the extent it asks APS to create information and perform analyses that are not in existence, and the request is irrelevant and immaterial to the extent it seeks information about projects and expenses not in the Test Year or Post-Test Year Plant period. Four Corners Power Plant is a jointly owned plant, operated by APS. Any decisions about retirement or early closure must be made jointly by the co-owners and cannot be made solely by APS. Currently, APS plans to exit the plant in 2031.

CITIZEN GROUPS' SECOND SET OF DATA REQUESTS TO ARIZONA PUBLIC SERVICE COMPANY REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN DOCKET NO. E-01345A-19-0236 JUNE 15, 2020

Citizen Groups 2.12: Provide copies of the output files for APS planning models used in the preparation of the company's 2020 Integrated Resource Plan.

Response: Please see the attached spreadsheets ExcelAPS19RC01441, ExcelAPS19RC01442 and ExcelAPS19RC01443. These spreadsheets are Highly Confidential and are being provide pursuant to an executed Protective Agreement in this docket.

Witness: Brad Albert

CITIZEN GROUPS' SECOND SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO
DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-19-0236
JUNE 15, 2020

Citizen Groups 2.14: For each scenario examined in APS's 2020 Integrated Resource Plan please provide the following information for each of Four Corners Units 4 and 5 for each of the years 2020-2038.

a. Annual generation and capacity factors
b. Annual Forced Outage Rates and Equivalent Forced Outage Rates
c. Annual Equivalent Availability Factors
d. Annual fixed O&M expenses
e. Annual non-fuel O&M expenses
f. Annual fuel costs
g. Annual environmental capital investments (CAPEX)
h. Annual non-environmental CAPEX
i. Annual value forecast to be included in APS's rate base

Response: Subject to and without waiving the Objections of Arizona Public Service Company to Citizen Groups Second Set of Data Requests provided on June 29, 2020, APS provides the following response:

This information is Highly Confidential and is being provided pursuant to an executed Protective Agreement in this docket. Please note that the information provided below reflects APS ownership share. Some of the information is available and provided on a unit level, while some is only available and provided at a plant level.

a. Annual generation can be found in the response to Citizen Groups 2.12. Capacity factors can be found in Attachment D.1(A)(2) in the APS 2020 Integrated Resource Plan.

b. The Annual Forced Outage Rate for Four Corners Unit 4 is 11.5% for all years. The Annual Forced Outage Rate for Four Corners Unit 5 is 14.8% for all years.

c. Please see the attached spreadsheet ExcelAPS19RC01445.

d. Annual fixed O&M expenses can be found in Attachment D.1(A)(6) in the APS 2020 Integrated Resource Plan.

e. Annual non-fuel (variable) O&M expenses can be found in the Company's response to Citizen Groups 2.12.

f. Annual fuel costs can be found in the Company's response to Citizen Groups 2.12.

g. Please see the attached spreadsheet ExcelAPS19RC01446. In the IRP, APS does not distinguish between environmental

Response to Citizen Groups 2.14 (continued):

and non-environmental CAPEX.

h. Please see the Company's response to part g.

i. Please see the attached spreadsheet ExcelAPS19RC01447. Please note that this is a planning document and is not used for rate making purposes.

Witness: Brad Albert

Attachment TC-3

Confidential Discovery Responses

Confidential Information

This file is marked confidential and will be made available for those parties who have signed the Protective Agreement.

Attachment TC-4

Highly Confidential Discovery Responses

Highly Confidential Information

This file contains Highly Confidential Information and will be made available for those parties who have signed the Protective Agreement.